

Stack Gas Reheat Evaluation

Radian Corp.
Austin, TX

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

Mar 80



U.S. Department of Commerce
National Technical Information Service

NTIS

TECHNICAL REPORT DATA (Please read Instructions on the reverse before completing)		
1. REPORT NO. EPA-600/7-80-051	2.	3. RECIPIENT'S ACCESSION NO. PB 80 196850
4. TITLE AND SUBTITLE Stack Gas Reheat Evaluation		5. REPORT DATE March 1980
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S) W.R. Menzies, C.A. Muela, and G.P. Behrens		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS Radian Corporation 8500 Shoal Creek Boulevard Austin, Texas 78766		10. PROGRAM/ELEMENT NO. INE827
		11. CONTRACT/GRANT NO. 68-02-2642
12. SPONSORING AGENCY NAME AND ADDRESS EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711		13. TYPE OF REPORT AND PERIOD COVERED Final: 6/77-2/80
		14. SPONSORING AGENCY CODE EPA/600/13
15. SUPPLEMENTARY NOTES IERL-RTP project officer is Theodore G. Brna, Mail Drop 61, 919/541-2683.		
16. ABSTRACT The report gives results of technical and economic evaluations of stack gas reheat (SGR) following wet flue gas desulfurization (FGD) for coal-fired power plants. The evaluations were based on information from literature and a survey of FGD users, vendors, and architect/engineer (A/E) firms. The report summarizes SGR processes and their features and their commercial operating experience. It addresses benefits and energy requirements associated with SGR, and describes a developed method for estimating reheat costs. SGR can protect equipment downstream of a wet scrubber from corrosion, reduce the potential for acid rainout near the plant stack, preclude visible stack plumes, and reduce ground-level pollutant concentrations by increasing plume buoyancy. SGR users have generally installed it for equipment protection (30° F or higher reheat is normally specified). Most A/E firms and vendors do not recommend SGR as a necessary part of a wet FGD system; they prefer the higher reliability of indirect hot air injection. Plants slated for operation with wet scrubbers in 1983 will use inline (30%), bypass (24%), and indirect hot air (14%) reheat or no reheat (wet stacks, 20%). Inline reheat is generally less costly but has lower reliability than indirect hot air reheat. Bypass reheat is the most economical; but its application is limited by SO ₂ emission regulations.		
17. KEY WORDS AND DOCUMENT ANALYSIS		
a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field Group
Pollution Desulfurization Flue Gases Reheating Coal Combustion Evaluation	Pollution Control Stationary Sources Stack Gas Reheat	13B 07A, 07D 21B 13A 21D 14B
18. DISTRIBUTION STATEMENT Release to Public	19. SECURITY CLASS (This Report) Unclassified 20. SECURITY CLASS (This page) Unclassified	21. NO. OF PAGES 22. PRICE

United States
Environmental Protection
Agency

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

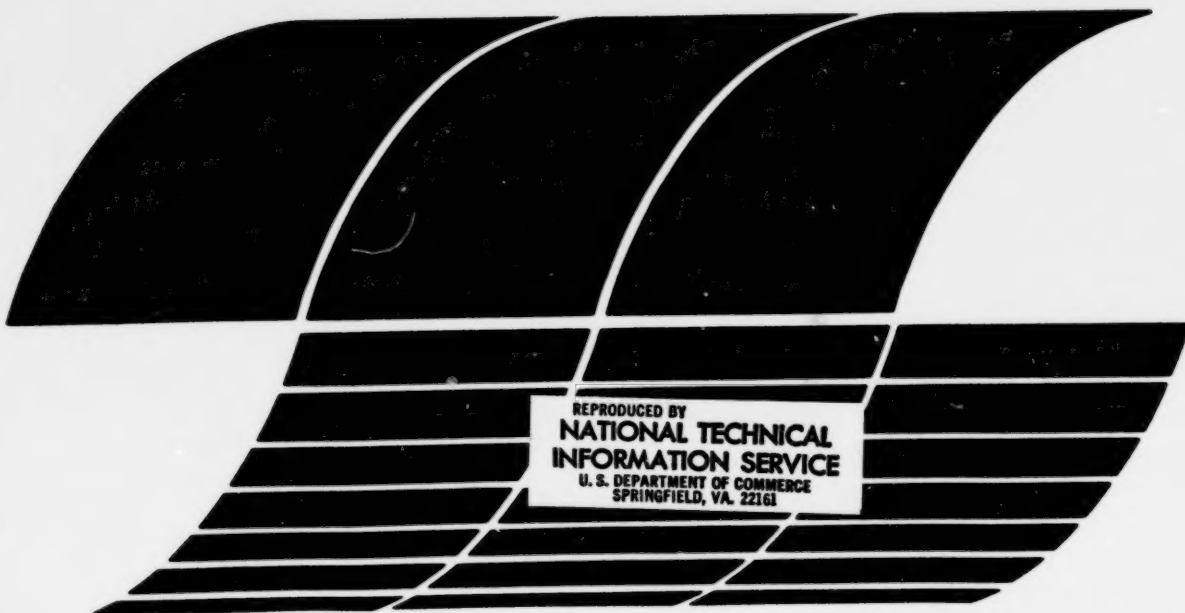
EPA-600/7-80-051
March 1980

PR80-196850



Stack Gas Reheat Evaluation

Interagency Energy/Environment R&D Program Report



REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into nine series. These nine broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The nine series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development
8. "Special" Reports
9. Miscellaneous Reports

This report has been assigned to the INTERAGENCY ENERGY-ENVIRONMENT RESEARCH AND DEVELOPMENT series. Reports in this series result from the effort funded under the 17-agency Federal Energy/Environment Research and Development Program. These studies relate to EPA's mission to protect the public health and welfare from adverse effects of pollutants associated with energy systems. The goal of the Program is to assure the rapid development of domestic energy supplies in an environmentally-compatible manner by providing the necessary environmental data and control technology. Investigations include analyses of the transport of energy-related pollutants and their health and ecological effects; assessments of, and development of, control technologies for energy systems; and integrated assessments of a wide range of energy-related environmental issues.

EPA REVIEW NOTICE

This report has been reviewed by the participating Federal Agencies, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policies of the Government, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

EPA-600/7-80-051

March 1980

Stack Gas Reheat Evaluation

by

W.R. Menzies, C.A. Muela,
and G.P. Behrens

Radian Corporation
8500 Shoal Creek Boulevard
Austin, Texas 78766

Contract No. 68-02-2642
Program Element No. INE827

EPA Project Officer: Theodore G. Brna

Industrial Environmental Research Laboratory
Office of Environmental Engineering and Technology
Research Triangle Park, NC 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

ABSTRACT

Technical and economic evaluations of stack gas reheat (SGR) following wet flue gas desulfurization (FGD) for coal-fired power plants were made. These evaluations were based on information from literature and a survey of FGD users, vendors, and architect/engineer (A/E) firms. Reheat processes and their features and commercial operating experience were summarized. The benefits and energy requirements associated with SGR were addressed, and a method for estimating reheat costs was developed and illustrated.

Stack gas reheat can protect equipment downstream of a wet scrubber from corrosion, reduce the potential for acid rainout near the plant stack, preclude visible stack plumes, and reduce ground level pollutant concentrations by increasing plume buoyancy. Reheat users have generally installed SGR for equipment protection (30°F or greater level of reheat is normally specified). Most A/E firms and vendors do not recommend SGR as a necessary part of a wet FGD system and prefer indirect hot air injection because of higher reliability if reheat is requested by customers.

Plants slated for operation with wet scrubbers in 1983 will use inline (30 percent), bypass (24 percent), and indirect hot air (14 percent) reheat or no reheat (wet stacks, 20 percent). Inline reheat is generally less costly but exhibits lower reliability than indirect hot air injection reheat. Bypass reheat is the most economical system, however, its application is limited by SO₂ emission regulations.

CONTENTS

Abstract.....	iii
Figures.....	vi
Tables.....	viii
Acknowledgments.....	xi
1. Introduction.....	1
2. Summary.....	3
Stack gas reheat state-of-the-art.....	4
The need for reheat.....	8
Economic evaluation.....	15
3. Conclusions.....	20
The need for stack gas reheat.....	20
Survey of current practice.....	21
Evaluation and comparison of reheat configurations.....	21
4. Recommendations.....	24
5. Survey of Current Practice.....	25
Literature review.....	25
Survey results.....	32
Survey summary and conclusions.....	68
6. The Need for Stack Gas Reheat.....	71
Downstream equipment corrosion.....	72
Visible plume formation.....	87
Acid rainout in the vicinity of the stack.....	101
Increased ground-level pollutant concentrations.....	110
Applicability of bypass reheat.....	124

CONTENTS (continued)

7. Stack Gas Reheat Economics.....	129
Availability and cost of steam.....	130
Reheat exchanger sizing.....	134
Costs of various reheat configurations.....	136
Comparison of reheat system economics.....	165
References.....	170
Appendices	
A. Description of Radian's dispersion and wet plume models.....	176
B. Questionnaire forms.....	183
C. Generalized 500-MW steam cycle--development and steam cost analysis.....	209
D. Equipment sizing bases (reheat exchangers, fans, stacks).....	235
E. Reheat configuration component cost assumptions.....	254
F. Factors for conversion of English units to the international system of units (SI).....	300

FIGURES

<u>Number</u>		<u>Page</u>
1	Simplified schematics of various reheat configurations.....	5
2	Simplified schematics of various reheat configurations.....	30
3	Calculated temperature rise due to work of compression.....	78
4	Simplified schematic of FGD systems with forced and induced draft primary fans.....	79
5	Induced draft fan arrangement of inline, indirect, and direct combustion reheat configurations.....	81
6	Psychrometric chart showing state point of flue gas-air mixture during combustion, scrubbing, and reheat.....	88
7	Psychrometric chart showing the influence of relative humidities on the temperature range at which an unscrubbed flue gas will form a visible plume.....	96
8	Psychrometric chart showing the impact of 50°F reheat on visible plume length at different relative humidities.....	98
9	Impact of scrubbing and reheating on visible plume length at various ambient air temperatures and relative humidities.....	99
10	Predicted impact of wind speed and reheat on detached distance of visible plume.....	100
11	Model-predicted time lengths that the density of the condensed water vapor in visible plumes was greater than 3.12×10^{-5} lb/ft ³ for various reheat levels.....	107
12	Model-predicted maximum densities attained by condensed water vapor in visible plumes for various reheat levels.....	108
13	Model-predicted three-hour, ground-level SO ₂ concentration downwind of the stack for an unstable atmosphere.....	113
14	Model-predicted three-hour, ground-level NO _x concentration downwind of the stack for an unstable atmosphere.....	114
15	Model-predicted three-hour, ground-level SO ₂ concentration downwind of the stack for a neutral atmosphere.....	116
16	Model-predicted three-hour, ground-level NO _x concentration downwind of the stack for a neutral atmosphere.....	117

FIGURES (continued)

<u>Number</u>		<u>Page</u>
17	Schematics of different fan arrangements used to develop economics of various reheat configurations.....	139
18	Simplified schematic of indirect hot air reheat configuration with a forced draft primary fan arrangement.....	149
19	Simplified schematic of indirect hot air reheat configuration with an induced draft primary fan.....	154
20	Simplified schematic of indirect hot air reheat configuration with a forced draft primary fan arrangement.....	156
21	Simplified schematic of exit gas recirculation reheat with an induced draft primary fan arrangement.....	159
22	Simplified schematic of an advanced EGR reheat configuration....	161
23	Schematics of direct combustion reheat configurations with forced and induced draft primary fan arrangements.....	163

TABLES

<u>Number</u>		<u>Page</u>
1	Reheat Configuration Operating Characteristics.....	7
2	FGD Process Vendor and Architect/Engineering Company Responses.	8
3	Heat Input Required to Prevent the Occurrence of Moisture Downstream of the Scrubber.....	10
4	Reheat Required to Prevent a Visible Plume.....	12
5	Impact of Stack Gas Reheat on Maximum Three-Hour Ground-Level Pollutant Concentrations.....	14
6	Stack Gas Reheat Economic Evaluation Summary (1978 \$).....	17
7	FGD Process Characterization.....	27
8	Reheat Configurations and Potential Energy Sources.....	33
9	FGD Process Vendor- and A/E-Preferred Reheat Systems.....	35
10	Electric Utility Units and Specified Type of Reheat.....	37
11	Startup Dates For Various Reheat Systems.....	40
12	Reheat Temperature Levels at Operating and Planned Units.....	41
13	Reheat Energy Sources.....	42
14	Inline Reheat Systems.....	45
15	Indirect Hot Air Reheat Systems.....	54
16	Direct Combustion Reheat Systems.....	58
17	Bypass Reheat Systems.....	62
18	Wet Stack Systems.....	65
19	Reheat Configuration Operating Characteristics.....	70
20	Temperature Drop Through Duct With and Without Insulation.....	74
21	Flue Gas Temperature Drop Due to Heat Loss From a 600-Foot Stack.....	75
22	Heat Input Required to Prevent the Occurrence of Moisture Downstream of the Scrubber.....	86
23	Reheat Required to Prevent a Visible Plume.....	90
24	Parameters for Utilization in Wet Plume Model (500-MW Plant)...	92

TABLES (continued)

<u>Number</u>		<u>Page</u>
25	Visible Plume Length and Detached Distance (Neutral Stratification, Wind Speed = 5 MPH).....	93
26	Visible Plume Length and Detached Distance (Neutral Stratification, Wind Speed = 15 MPH).....	94
27	Visible Plume Length and Detached Distance (Neutral Stratification, Wind Speed = 25 MPH).....	95
28	Plume Characteristics for Various Scrubbing and Reheat Levels (Neutral Atmosphere, Wind Speed = 5 MPH).....	104
29	Plume Characteristics for Various Scrubbing and Reheat Levels (Neutral Atmosphere, Wind Speed = 15 MPH).....	105
30	Plume Characteristics for Various Scrubbing and Reheat Levels (Neutral Atmosphere, Wind Speed = 25 MPH).....	106
31	Flue Gas, Stack and Emission Parameters.....	112
32	Impact of SO ₂ Removal Efficiency on Maximum Three-Hour Ground-Level SO ₂ Concentrations.....	118
33	Impact of Stack Height on Maximum Three-Hour Ground-Level Pollutant Concentrations.....	119
34	Maximum Annual Average Pollutant Concentrations.....	120
35	Seasonal Effect of Reheat on Ground-Level SO ₂ Concentration.....	122
36	Available Steam Conditions in the Base Case Steam Cycle.....	131
37	Cost (1978 \$) of Various Steam Levels for Reheating Flue Gas.....	133
38	Capital and Operating Cost Bases Used to Develop Economics of Various Reheat Configurations.....	135
39	Plant Characteristics and FGD Configurations Used to Develop Economics of Various Reheat Configurations.....	138
40	Cost Summary Sheet for Inline Reheat.....	140
41	Costs of Inline Reheat Using Various Dry, Saturated Steams.....	142
42	Summary and Comparison of Economics for Inline Reheat (Sensitivity Analyses).....	144
43	Evaluation of Exchanger Tube Metallurgy for Inline Reheat (1978 \$).....	147
44	Cost Summary Sheet for Indirect Hot Air Reheat.....	150
45	Economics of Using Dry, Saturated Steam in Indirect Hot Air Reheat Systems.....	151

TABLES (continued)

<u>Number</u>		<u>Page</u>
46	Summary and Comparison of Economics Developed for Indirect Hot Air Reheat Sensitivity Studies.....	153
47	Cost Summary Sheet for Exit Gas Recirculation.....	157
48	Cost of Using Dry, Saturated Steam to Reheat Flue Gas With an Exit Gas Recirculation System.....	158
49	Economics for Exit Gas Recirculation Sensitivity Studies.....	160
50	Costs of Direct Combustion Reheat (1978 \$).....	162
51	Stack Gas Reheat Economic Evaluation Summary (1978 \$).....	166
52	Impact of Assumptions on Economics of 50°F Reheat With Inline Reheat System.....	169

ACKNOWLEDGMENTS

The authors would like to express their appreciation to Dr. Theodore G. Brna, EPA Project Officer, for his advice and technical guidance provided throughout the project.

Dr. Phillip S. Lowell provided substantial technical input to this program and his work is gratefully acknowledged.

Special thanks are also given to Ms. Christy K. Holcomb for her efforts in preparing the report.

In addition, numerous individuals contacted as part of an OMB-approved survey contributed their advice and assistance during the course of the project. These individuals are listed in the Reference Section of the report.

SECTION 1

INTRODUCTION

Stack gases from utility boilers without flue gas desulfurization (FGD) are normally discharged to the atmosphere at a temperature of 250°F to 300°F. In this temperature range, the flue gas is relatively dry and noncorrosive. The wet FGD processes currently being used commercially in the United States cool the boiler flue gas from about 300°F to its adiabatic saturation temperature, typically 125-140°F. This saturated (with water vapor) flue gas may cause the following problems:

- (1) The corrosion of equipment downstream of the scrubber (duct work, fan, stack) due to the presence of moisture, acid, and chlorides.
- (2) The occurrence of acid rainout* in the vicinity of the plant stack.
- (3) The formation of a visible plume which may be hazardous to any ground and air traffic in the vicinity of the power plant.
- (4) High ground-level pollutant concentrations downwind from the stack due to poor plume buoyancy.

Reheating the saturated flue gas to a temperature above its saturation temperature will lessen the impacts of each of these four potential problems.

The objectives of this study were to survey the utility industry to determine their present practices regarding the use of stack gas reheat (SGR),

*The term acid rainout is used in this report to refer to rain in the vicinity of the plant stack to distinguish it from the term acid rain which is used to describe a different phenomenon.

determine how much reheat is needed and its costs, and compare the economics and reliabilities of the available reheat methods.

The various analyses conducted, as well as the significant results and recommendations, are discussed in the following sections:

Sections 1-4 - Introduction, Summary, Conclusions, Recommendations

Section 5 - Current industrial practices with respect to the use of reheat are reported and analyzed. Operating data for commercially available reheat configurations are also presented. This information reflects data obtained from reheat users, FGD process vendors, architect/engineering companies, and available literature.

Section 6 - The problems (presented on page 1) that may be caused by the use of wet FGD processes and the mechanisms by which these problems occur are discussed. The quantity of reheat that is theoretically required to eliminate these problems (where possible) and the impact of varying degrees of reheat are also evaluated.

Section 7 - The capital requirements and operating costs for SGR systems providing 50°F of reheat are estimated and discussed. A methodology is developed for estimating steam and hot water costs in power plants using SGR. The annualized costs for four commercially available and/or promising reheat configurations are developed and compared. The sensitivity of the costs of these configurations to various design and operating parameters is also analyzed.

It should be noted that English units have been used throughout this report for the convenience of the reader. These units can be readily converted to the International System of Units with the conversion factors presented in Appendix F of this report.

This report was submitted in fulfillment of Contract No. 68-03-2642 by Radian Corporation under the sponsorship of the U.S. Environmental Protection Agency. The majority of the project work was conducted from June, 1977 to September, 1978.

SECTION 2

SUMMARY

An economic and technical assessment of stack gas reheat (SGR) technology was conducted with the following approach:

- (1) A survey of the state-of-the-art in SGR practices and technology was conducted. Information was obtained from available literature and an OMB-approved questionnaire which was distributed to reheat users, flue gas desulfurization (FGD) process vendors, and architect/engineering (A/E) companies. The objectives of this survey were to:
 - Identify the problems associated with saturated flue gases resulting from wet scrubbing,
 - Identify commercially available and promising reheat techniques, and
 - Assess current industry practice and experience with SGR systems.
- (2) A theoretical evaluation of the need for reheat was performed. The objectives of this evaluation were to:
 - Identify the mechanisms causing the problems associated with wet stack gases,
 - Evaluate the impact of varying levels of SGR on these problems, and
 - Estimate the energy requirements and limitations associated with various reheat configurations.
- (3) Capital and operating costs for various SGR configurations were estimated. The analyses included:
 - Estimating and comparing the costs for the principal reheat configurations, and
 - Analyzing the sensitivity of SGR economics to changes in important parameters.

STACK GAS REHEAT STATE-OF-THE-ART

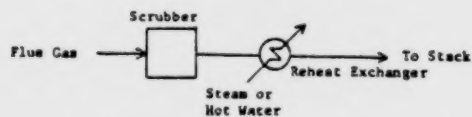
Based on a review of the various types of FGD processes, it was determined that processes that cool and saturate the flue gas with water may require stack gas reheat. Saturated stack gases may cause the following problems compared to unscrubbed stack gases:

- (1) The corrosion of equipment downstream of the scrubber due to the occurrence of condensation
- (2) The formation of a visible plume which may be hazardous to ground and air traffic in the vicinity of the power plant
- (3) The occurrence of acid rainout in the vicinity of the plant stack
- (4) Increased ground-level pollutant concentrations (compared to the unscrubbed flue gas) downwind from the stack due to poor plume buoyancy

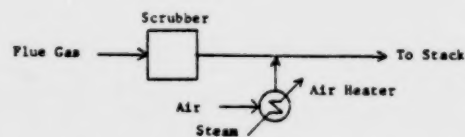
The impact of these problems can be reduced or eliminated by using SGR to heat the saturated stack gas above its dew point.

Several methods have been employed or envisioned to reheat scrubbed flue gas. Schematics of these methods are presented in Figure 1 and descriptions are presented below:

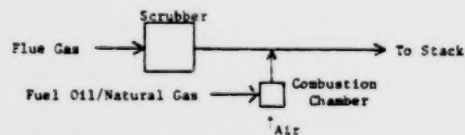
- (1) Inline reheat - The scrubbed flue gas is heated by passing it through a heat exchanger located in the duct work.
- (2) Indirect hot air injection reheat - Air is heated in an exchanger and then mixed with the scrubbed flue gas.
- (3) Direct combustion reheat - Hot combustion gases which are generated by firing fuel oil or natural gas are mixed with the scrubbed flue gas.
- (4) Exit gas recirculation (EGR) reheat - A portion of the reheated scrubbed flue gas is passed through the reheater, heated to a higher temperature, and then mixed with the saturated flue gas.



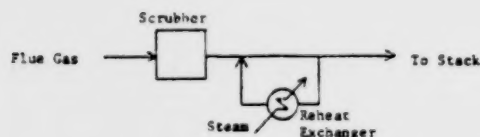
(a) Inline Reheat



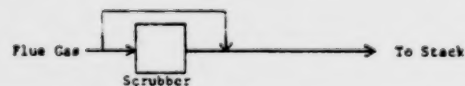
(b) Indirect Hot Air Reheat



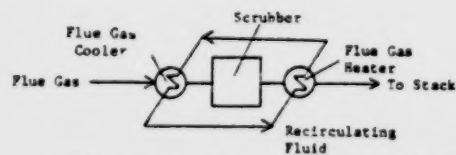
(c) Direct Combustion Reheat



(d) Exit Gas Recirculation Reheat



(e) Bypass Reheat



(f) Waste Heat Recovery Reheat

Note: Fans and pumps not shown for simplicity.

Figure 1. Simplified schematics of various reheat configurations.

- (5) Bypass reheat - A portion of the boiler flue gas is routed around the scrubber and mixed with the scrubbed flue gas.
- (6) Waste heat recovery reheat - Hot unscrubbed flue gas is used to heat the scrubbed flue gas in a dual exchanger arrangement.¹

Table 1 presents a summary of the advantages, disadvantages, and operating characteristics of the various reheat configurations as applied to new and retrofit applications.

Questionnaires were distributed to reheat users (limited to coal-fired power plants with scrubbers), FGD process vendors, and architect/engineering companies in order to determine current trends in the use of stack gas reheat, identify those configurations that were or are used commercially, and to obtain operating and reliability data for these configurations. The responses to those questionnaires reflect industry practice and experience as of mid-1978. These responses indicate that the majority of FGD process vendors and A/E companies do not recommend the use of SGR as a necessary part of a wet scrubbing system. Additional data obtained from FGD process vendor and design responses are presented in Table 2.

Data obtained from the users of reheat indicate:

- (1) The major reason given for using reheat is equipment protection against corrosion.
- (2) The second reason most often given for using reheat is increased plume buoyancy for pollutant dispersion.
- (3) Plants presently using stack gas reheat generally heat the scrubbed flue gas by 30°F or more in order to accomplish items 1 and/or 2.
- (4) The inline, indirect hot air, direct combustion, and bypass reheat methods are the commercially-used configurations. Inline reheat is the most widely used configuration.

- (5) The bypass reheat systems and the no reheat system (wet stacks) outnumber other reheat systems for power plants coming onstream after January 1, 1978 (this includes planned facilities for which information was available).
- (6) Current and future use of bypass reheat is restricted by SO₂ emission standards.

TABLE 2. FGD PROCESS VENDOR AND ARCHITECT/ENGINEERING COMPANY RESPONSES

Configuration	Recommendations ^a	Remarks
Inline	3	Recommended reheat materials are site specific but range from carbon steel to Inconel 625. Soot blowers should be used.
Indirect Hot Air	10	Finned carbon steel or copper tubes should be used.
Direct Combustion	1	
Bypass	7	Some did not recommend bypass because it was felt that future SO ₂ emission standards would limit applicability.
Exit Gas Recirculation	0	Not commercially proven.
Waste Heat Recovery	0	Not commercially proven. Heat exchanger equipment material requirements are uncertain.

^a Although 12 A/E and vendors responded, some firms recommended more than one form of reheat. These are the reheat configuration recommendations that the respondents would make if a client requests an SGR system in connection with the wet scrubber.

THE NEED FOR REHEAT

An analysis of each of the problems associated with a wet stack gas and the benefits and energy penalties that result when stack gas reheat is utilized are presented below.

Equipment Corrosion

Because the scrubbed flue gas contains SO_2 , SO_3 , CO_2 , chlorides, NO_x , and some sulfuric acid mist, the flue gas can be very corrosive in the presence of condensed water vapor. A study to determine the impact of reheat on the presence of moisture in the system was conducted. The heat input required to prevent condensation is dependent on several variables, with the most important variables being:

- (1) Heat losses from the duct work and stack
- (2) Quantity of mist carry-over from the scrubber
- (3) Reheat configuration used

Responses to the questionnaire indicated that a temperature drop of about 5°F is typically experienced in new plants from the reheater or scrubber exit to the top of the stack. This provides a good estimate of the heat loss through the duct and stack walls. This verifies calculations performed as part of this study.

The theoretical reheat energy input required to prevent the occurrence of moisture downstream of the scrubber was calculated for inline, direct combustion, and indirect hot air reheat. These heat requirements are summarized in Table 3. A comparison of these data indicates that the indirect hot air reheat method requires more energy than inline or direct combustion reheat.

Industry users generally indicate that 30°F of reheat or more is required to adequately protect equipment from corrosion. In this assessment of SGR, a detailed evaluation of the mechanism of mist vaporization by reheat in the duct work and stack was not undertaken. Modelling liquid (mist carryover) droplet size, characteristics, and residence time in the

TABLE 3. HEAT INPUT REQUIRED TO PREVENT THE OCCURRENCE OF MOISTURE DOWNSTREAM OF THE SCRUBBER

	Reheat Configuration			
	In Line	Direct Combustion	Indirect Hot Air	
Entrained Liquid (qt/sec) ¹ (lb/hr)	0.012 180	0.805 8840	0.012 130	0.805 8840
Dew Point Temperature at Stack Exit (°F)	129	129.5	129.5	128
Ambient Air Characteristics				
Temperature (°F)	-	60	60	60
Relative Humidity (%)	-	50	50	50
Heated Air Temperature (°F)	-	-	400	400
Flow Rate (lb/hr)	-	-	92,500	212,500
Assumed Heat Loss (10 ⁶ Btu/hr) ²	6.6	6.6	6.6	6.6
Heat Required For Vaporizing Entrainment (10 ⁶ Btu/hr)	0.13	9.0	0.13	9.0
Sensible Heat Required for Reheat Medium ³ (10 ⁶ Btu/hr)	-	0.01	0.02	3.6
Theoretical Heat Required to Prevent Presence of Moisture (10 ⁶ Btu/hr) (% of h ₂ per input)	6.7 0.15	15.6 0.35	6.7 0.15	19.2 0.43

¹Reference 1 reports entrainment loading of .012 qt/sec for a bottom wash mist eliminator and .805 qt/sec for a top wash mist eliminator.
²Total heat losses assumed to be equivalent for all configurations and correspond to a 5°F drop in flue gas temperature.
³This sensible heat equals the heat required to raise the reheat medium from its ambient temperature to the stack exit temperature.

Bases:

- (1) 500 MW unit
- (2) 9,000 Btu/kWh heat rate
- (3) Forced draft fan configuration (with respect to the scrubber)
- (4) Flue gas saturation temperature = 129°F
- (5) Flue gas flow rate = 5.14 × 10⁵ lb/hr
- (6) Flue gas heat capacity = 0.26 Btu/lb-°F
- (7) For direct combustion, natural gas ambient temperature assumed to be 60°F.
- (8) Potential and kinetic energy changes considered negligible.

Reproduced from
best available copy.

duct work and stack should provide insight into why as much as 50°F of reheat is needed to protect downstream equipment.

Visible Plume Formation

The heat input to wet flue gas required to prevent a visible plume was determined for the inline and indirect hot air configurations at various ambient air temperatures and relative humidities (see Table 4). The results of these analyses show that the heat input required to prevent a visible plume for the two configurations is approximately the same. The quantity of energy required to eliminate a visible plume under all ambient conditions is prohibitively large. For example, at 32°F and 100 percent relative humidity, about 9 percent of the boiler heat input would be required to prevent a visible plume.

Acid Rainout in the Vicinity of the Plant Stack

Acid rainout may be caused by the condensation of acid vapor in the system and its subsequent entrainment, entrainment of condensed water vapor which has reacted with SO₂ and then oxidized to sulfuric acid (H₂SO₄), and/or condensation of acid vapor when it exits the stack. Reheat can reduce the potential for acid rain by preventing the occurrence of condensation; however, the degree of this reduction cannot be readily quantified since the percentage of acid rain attributable to various mechanisms is undetermined.

A plume simulation program was used to study the impact of reheat on the density of condensed water vapor in a visible plume. Several levels of reheat (increase in flue gas temperature), ambient temperature, relative humidity, and wind speed were considered in this study. These analyses showed that reheat can decrease the concentration of condensed water vapor in the plume and, consequently, the potential for acid rain. However, this impact is dependent on climatic conditions and there are some conditions, such as low temperatures and high humidities, at which reheat has little or no effect.

TABLE 4. REHEAT REQUIRED TO PREVENT A VISIBLE PLUME

Reheat Configuration Ambient Air Temperature (°F) Relative Humidity (%)	Inline			Indirect Hot Air Injection		
	60	60	32	60	60	32
	50	100	100	50	100	100
Flue Gas (at scrubber exit) Saturation Temperature (°F)	129	129	129	129	129	129
Heated Air Temperature (°F)	-	-	-	400	400	400
Quantity of Heated Air Required (10 ⁶ lb/hr) -	-	-	-	0.84	1.75	4.52
Stack Gas Reheat Temperature Required To Prevent Visible Plume (°F)	183	240	439	166	196	253
Reheat Required to Prevent Visible Plume Formation (10 ⁶ Btu/hr)	71.0	149.0	416.0	71.0 (70.5)	149.0 (147.7)	416.0 (412.0)
(% Boiler Input)	1.58	3.31	9.24	1.58 (1.56)	3.31 (3.28)	9.24 (9.15)

Bases and Comments:

- (1) Flue gas flow rate (existing scrubber) is 5.14×10^6 lb/hr (representative of a 500-MW plant).
- (2) Flue gas water content (existing scrubber) is assumed to be 14.7 percent (vol.) for all cases.
- (3) A heat rate of 9000 Btu/kWh was assumed.
- (4) Heat losses in duct work and stack are assumed to be negligible.
- (5) Liquid entrainment from the mist eliminator is assumed to be zero.
- (6) Primary fan arrangement is forced draft with respect to the scrubber.
- (7) Reheat requirements in parentheses for indirect hot air were developed by taking credit for heat due to work of compression produced by the auxiliary fan. The pressure drop in the air heater was assumed to be 6 in. H₂O and an 85 percent fan efficiency was also assumed.

Totally eliminating the presence of sulfuric acid in the system would involve vaporizing any aqueous acid or acid mist. This would require enough heat input to raise the flue gas temperature above the acid dew point (approximately 300°F). This heat input is considerably more than is generally used by industry (0 to 100°F of reheat). Moreover, raising the flue gas temperature to 300°F does not insure that condensation of sulfuric acid vapor will not occur when the flue gas exits the stack and mixes with ambient air. Currently, not enough data are available to identify the benefit which would be obtained with reheat beyond the level required to prevent water vapor condensation in the stack or duct work.

Pollutant Dispersion

Scrubbing the boiler flue gas can adversely affect ground-level pollutant concentrations. By cooling and saturating the flue gas with water, the scrubbing process causes poor plume buoyancy which, in turn, reduces the dispersion of pollutants exiting the stack. Reheat will reduce ground-level pollutant concentrations and a plume dispersion model was used to study this effect. The bases and results of part of this study are presented in Table 5 and show that:

- (1) Scrubbing (without reheat) significantly reduces the maximum three-hour ground-level SO₂ concentration that results from an unscrubbed flue gas. Scrubbing, however, increases the ground-level concentration of NO_x above the values for the corresponding unscrubbed flue gas. However, in all cases the pollutant concentrations are well below applicable air quality standards.
- (2) Reheating the scrubbed flue gas by 50°F can significantly reduce the ground-level NO_x and SO₂ concentration (on a percentage basis) compared to the ground-level concentrations obtained with scrubbing and no reheat.
- (3) Reheating the scrubbed flue gas by an additional 50°F (100°F of total reheat) further reduces the ground-level SO₂ and NO_x concentrations, but the relative reduction attained is diminished.
- (4) The maximum ground-level concentration of NO_x from an unscrubbed stack gas (at 300°F) remains significantly lower than the maximum

TABLE 5. IMPACT OF STACK GAS REHEAT ON MAXIMUM THREE-HOUR GROUND-LEVEL POLLUTANT CONCENTRATIONS

Stack Height (ft)	Scrubbing-Reheat Level	Maximum Ground Level SO ₂ Concentration		Maximum Ground Level NO _x Concentration	
		µg/m ³	% of unscrubbed	µg/m ³	% of unscrubbed
300	Unscrubbed	180	100	21	100
	Scrubbed with no reheat	98	54	58	276
	Scrubbed with 50°F reheat	70	39	42	200
	Scrubbed with 100°F reheat	55	31	32	152
600	Unscrubbed	78	100	9	100
	Scrubbed with no reheat	30	38	18	200
	Scrubbed with 50°F reheat	24	31	14	156
	Scrubbed with 100°F reheat	20	26	12	133

Bases:

- (1) Neutral atmospheric stability
- (2) 18-mph wind speed
- (3) 500-MW plant
- (4) Atmospheric temperature is assumed to be 60°F.
- (5) 80 percent SO₂ removal
- (6) 30.6-foot stack diameter
- (7) Stack gas velocities
 - (a) unscrubbed - 35.0 ft/sec
 - (b) scrubbed - 28.7 ft/sec
 - (c) scrubbed with 50°F reheat - 31.1 ft/sec
 - (d) scrubbed with 100°F reheat - 33.5 ft/sec
- (8) Unscrubbed stack gas temperature - 300°F
- (9) Scrubbed stack gas temperature (with no reheat) - 129°F

ground-level NO_x concentration obtained from a scrubbed stack gas (with 100°F of reheat).

- (5) The impacts of reheat on maximum ground-level concentrations are lessened at taller stack heights.

A comparison of the effect of inline and indirect hot air reheat on ground-level pollutant concentration showed that for the same degree of reheat (equivalent stack exit temperature), the indirect hot air scheme produces the lowest ground-level pollutant concentrations. However, the volume of injected air substantially increases the heat input required.

ECONOMIC EVALUATION

Capital requirements and operating costs were estimated for reheat systems* (inline, indirect hot air, direct combustion, EGR) providing 50°F of reheat to the scrubbed flue gases from a new 500-MW power plant. For those reheat configurations involving the design of heat exchangers, a design procedure was developed which allowed estimation of heat transfer surface area as a function of:

- (1) Steam quality (temperature, pressure)
- (2) Gas-side pressure drop
- (3) Tube size, spacing, and alignment

*Economics for bypass reheat were not estimated. Current SO_2 NSPS (1979) for power plants will not permit obtaining a reheat level of 50°F with bypass. However, with low sulfur coals, some bypass will be feasible and another method of reheat could be used to supplement the bypass reheat in order to obtain 50°F of reheat (if desired). Bypass reheat is the most economical reheat system up to the level permitted by environmental regulations. The economics methodology developed in this study for inline, EGR, indirect hot air and direct combustion can be used to estimate costs for 50°F of reheat using bypass and some other supplemental form of reheat. It is expected that some users of low sulfur coals will opt for this method of stack gas reheat.

- (4) Gas-heating medium approach temperatures
- (5) Scrubbed flue gas temperature (at scrubber exit) and level of reheat required

The reheat exchangers were not designed optimally, but reasonable design values were selected, and sensitivity analyses were performed.

Economic Results

Capital investment and operating costs for SGR systems will vary considerably depending on the following parameters:

- (1) Steam quality (temperature, pressure) and cost
- (2) Plant fuel cost (\$/10⁶ Btu)
- (3) Reheat configuration selected (EGR, inline, indirect hot air, direct combustion)
- (4) Exchanger design criteria
- (5) Reheat temperature desired
- (6) New or retrofit installation
- (7) Coal quality
- (8) Ductwork and stack heat losses
- (9) Mist carryover from scrubber mist eliminator

Ranges of costs for selected reheat cases are presented in Table 6. The costs are compared to costs for a new coal-fired plant and a limestone FGD system. It should be emphasized that the reheat costs shown are not for optimized designs. Reheat media (steam) quality and reheat exchanger parameters such as gas-side pressure drop, exchanger approach temperature, tube spacing, and use of finned tubes for hot air injection, have not been optimized. Also, the cost of reheater downtime (this may translate to scrubber downtime and boiler load reduction) has not been factored into the economic analysis.

TABLE 6. STACK GAS REHEAT ECONOMIC EVALUATION SUMMARY (1978 \$)

	Reheat System			
	In-line	Indirect Hot Air	Exit Gas Recirculation (EGR)	Direct Combustion
Reheat System Capital Requirement, 10 ⁶ \$	0.8 - 2.9 ^c	1.4 - 2.4	1.3 - 2.1	0.8
% of FGD System ^a Capital Requirement	1.1 - 3.6	1.9 - 3.2	1.7 - 2.8	1.1
% of Total Power Plant ^b Capital Requirement	0.2 - 0.7	0.4 - 0.6	0.3 - 0.5	0.2
Reheat System Annual Revenue Requirement (ARR), 10 ⁶ \$/year	1.5 - 1.7	1.9 - 2.1	1.4 - 1.6	1.6 - 2.0
% of FGD System ^a ARR	7.1 - 8.1	9.0 - 10.0	6.7 - 7.6	7.6 - 9.5
% of Total Power Plant ^b ARR	1.4 - 1.5	1.7 - 1.9	1.3 - 1.5	1.5 - 1.8
Bases				
Steam Quality	Dry, Saturated (165-600 psia)	Dry, Saturated (165-600 psia)	Dry, Saturated (165-600 psia)	-
Tube Material	Carbon Steel, 316 SS Inconel 625	Carbon Steel	Carbon Steel	-
Fuel Costs	Based on coal in new power plant at \$1/10 ⁶ Btu	Based on coal in new power plant at \$1/10 ⁶ Btu	Based on coal in new power plant at \$1/10 ⁶ Btu	\$3-4/10 ⁶ Btu No. 2 fuel oil

^a FGD system costs are taken as \$150/kW (capital requirement) and 6 mills/kWh (annual revenue requirement).

^b A new power plant (including FGD system) costs are taken as \$800/kW (capital requirement) and 31.4 mills/kWh (annual revenue requirement). See Appendix E.

^c For in-line reheat the large range for capital requirement is due primarily to the estimation of capital investments for several different tube materials.

Bases: (1) 50°F of reheat

(2) No mist carryover from scrubber

(3) No heat losses from ductwork and stack

(4) New 500-hp power plant with a heat rate of 9000 Btu/kWh

Since indirect hot air injection exhibits better reliability than inline reheat, this is a factor that may make indirect hot air injection competitive with other reheat systems for some users.

The following are noted (for the results given in Table 6):

- (1) Inline and EGR reheat are generally lower cost systems than direct combustion and indirect hot air injection reheat. EGR reheat, however, has not been tested commercially.
- (2) The better indirect hot air reheat reliability (compared to inline) may make indirect hot air reheat competitive with the other systems for some users.
- (3) Since the direct combustion system annual revenue requirement (ARR) is highly dependent on fuels which may be subject to availability constraints and high cost escalation, its use in new power plants is expected to be limited.

Impact of Assumptions on Economics

It is recognized that all power plants and scrubbers are different and, consequently, the reheat configurations used in these plants will also be different. The technical and economic assumptions used in the economic evaluation obviously do not apply to all situations. An evaluation of how changes in the bases affect the costs associated with an inline reheater was conducted. A base case inline reheater was selected for this analysis:

- (1) New 500-MW power plant
- (2) 9000 Btu/kWh plant heat rate
- (3) Heat losses from the stack and duct work (downstream of the mist eliminator) considered negligible
- (4) Entrainment from the mist eliminator considered negligible
- (5) 50°F flue gas temperature rise through the reheater
- (6) Carbon steel tubes in the reheater
- (7) 165 psia, dry, saturated steam as reheat steam

These assumptions are essentially the same as those used to prepare the information in Table 6. They resulted in a required heat input of 66.8×10^6 Btu/hr, a capital requirement of \$1,090,000, and an annual revenue requirement of \$1,520,000/yr. Several differences in the base case assumptions were evaluated as described below:

- Case A - The only base case values changed are related to the entrained mist and heat loss assumptions. The entrained mist is assumed to be 0.802 gr/scf. A 5°F temperature drop in the flue gas due to heat losses from the system equipment downstream of the mist eliminator is also assumed. These values increase the reheat requirement from 66.8×10^6 to 82.4×10^6 Btu/hr and the annual revenue required from $\$1.52 \times 10^6$ to $\$1.87 \times 10^6$. The new capital requirement is $\$1.34 \times 10^6$.
- Case B - In addition to the heat losses that were assumed in Case A, the reheater tube material is 316 stainless steel instead of carbon steel (base case). The change results in increasing the annual revenue requirement of the base case by about 26 percent to $\$1.91 \times 10^6$. The capital requirement of the reheat exchanger increases significantly (from $\$1.09 \times 10^6$ to $\$1.84 \times 10^6$).
- Case C - In this case the entrained mist is 0.802 gr/scf. Heat losses are equivalent to a 5°F drop in flue gas temperature. The reheater tube material is 316 stainless steel, while the plant heat rate is 10,350 Btu/kWh. These assumptions increase the base case reheat energy requirement from 66.8×10^6 Btu/hr to 95.9×10^6 Btu/hr and the annual revenue requirement from $\$1.52 \times 10^6$ to $\$2.20 \times 10^6$ (or a 45 percent increase in base case ARR). The new capital requirement is about $\$2.12 \times 10^6$.

SECTION 3

CONCLUSIONS

THE NEED FOR STACK GAS REHEAT

Since the impact of each of the problems that may be caused by wet flue gases (125-140°F) is affected differently by a given level of reheat, the need for reheat must be considered with respect to each separate problem. Based on the results of the analyses conducted for each problem, the following were concluded:

- (1) Stack gas reheat (SGR) is an effective method for reducing corrosion that may occur downstream of a wet FGD process (duct work, fan, stack). However, forced draft fans (relative to the scrubber) and lined stacks and ducts can also be used for corrosion protection caused by wet stack gases.
- (2) SGR can reduce the potential for acid rainout in the vicinity of the stack by elimination of moisture downstream of the scrubber and reduction of the condensed water vapor concentration in the plume. However, the mechanisms that result in acid rainout are not well enough understood to quantify the acid rainout that will occur at various atmospheric conditions and consequently, the expected reduction resulting from the use of reheat. Other alternatives for reducing the potential for acid rain are high efficiency mist eliminators, well-insulated ducts and stacks, and low velocity stacks.
- (3) SGR should not be used to eliminate a visible plume except under circumstances where air or ground transportation is significantly affected. There is no other alternative available for eliminating visible plumes.
- (4) SGR is a viable approach for reducing ground-level pollutant concentrations. Other alternatives, such as taller stacks (for NO_x and SO₂) and increased scrubber efficiency (for SO₂ removal), are also effective.

SGR should not be considered a necessary part of a wet scrubbing system since there are other alternatives available for minimizing the problems associated with wet stack gases (except for elimination of a visible plume which is, in most cases, considered uneconomical).

SURVEY OF CURRENT PRACTICE

A survey of reheat users, FGD process vendors, and architect/engineering (A/E) companies has shown that:

- (1) Reheat users cite equipment protection as the main reason for reheat. Enhancement of plume buoyancy is the reason specified most often after equipment protection.
- (2) Reheat users specify a 30°F (or greater) degree of reheat for adequate protection of equipment against corrosion.
- (3) Reheat users specify inline reheat most often compared to other configurations with economics being cited as the reason.
- (4) Reheat has been selected and is being planned for new power plant installations more often than wet stacks.
- (5) The majority of A/E contractors and FGD process vendors surveyed do not recommend SGR as a necessary part of a wet FGD system. If SGR is requested by the customer, then indirect hot air injection reheat is the preferred configuration of the majority of the A/E firms and FGD process vendors surveyed because of reliability.

EVALUATION AND COMPARISON OF REHEAT CONFIGURATIONS

Technical and economic evaluations were performed for five reheat configurations (inline, indirect hot air injection, exit gas recirculation, direct combustion, and FGD system bypass) as applied to the scrubbed flue gas from a power plant. The conclusions developed from these evaluations are:

(1) Energy requirements to achieve a specified stack gas exit temperature (level of reheat)

--Bypass reheat requires the least energy since waste heat (heat that would be lost during flue gas cooling and saturation of the flue gas in the scrubber) is used to reheat the stack gases. However, environmental regulations for SO₂ emissions control have limited this application.

--Direct combustion, inline, and exit gas recirculation reheat have similar energy requirements.

--Indirect hot air reheat has the highest energy requirement since both the injected air and flue gas must be heated to the stack exit temperature.

(2) Reliability

--The operating reliability of bypass reheat should be the best; however, operation of this reheat scheme will be restricted by SO₂ emission standards.

--Indirect hot air injection reheat reliability will also be good since the reheat exchanger does not come in contact with wet, corrosive flue gas.

--Inline reheat exchangers contact wet, saturated flue gas. Site specific factors (primarily coal sulfur and chloride content) may require expensive alloys (stainless steel, Inconel 625, etc.) to provide long exchanger life.

--Exit gas recirculation (EGR) reheat should exhibit better reliability than inline reheat but is commercially unproven.

--Direct combustion reheat is very reliable; however, availability and cost of fuels may limit its application.

(3) Capital and operating costs of reheat systems are highly dependent on

--Degree of reheat (°F)

--Mist carryover from the scrubber

--Heat losses from the duct work and stack

- Position of draft equipment relative to the scrubber
 - Power plant heat rate
 - Coal sulfur and chloride content
 - Type of reheat system
 - Type, quality, and cost of reheat media
 - Reheat exchanger tube material and life
- (4) Economics were developed for reheat systems (applied to a 500-MW power plant) which raise the stack exit temperature 50°F above the scrubber exit temperature.
- Inline reheat is generally less costly (annual revenue requirement) than indirect hot air reheat due to lower energy requirements. However, since reliability will be a major consideration in selecting reheat systems, the better reliability of indirect hot air reheat may make this system competitive for some users.
 - Exit gas recirculation reheat is economically attractive compared to the other reheat systems but has not been proven commercially.
 - Direct combustion reheat economics (compared to inline, EGR, and indirect hot air) depend heavily on delivered fuel price. Due to fuels availability and cost escalation considerations, this form of reheat is not expected to be used to a significant degree in new boiler-FGD applications.
 - Economics for bypass reheat were not developed because SO₂ emission regulations (June 11, 1979 Federal Register) for new coal-fired power plants will not permit a 50°F reheat level to be obtained.* However, bypass remains the most economical form of SGR available. For low sulfur coals, bypass reheat plus a supplemental reheater (inline, indirect hot air, EGR, or direct combustion) may be the most economical reheat configuration.
 - Capital and operating costs are relatively small compared to the cost of the scrubber and power plant. Capital investment for the various systems are less than 1 and 5 percent of the capital investment for the complete power plant and scrubber, respectively. Annualized costs are less than 3 and 15 percent of the annualized costs for the complete power plant and scrubber, respectively.

*Unless a supplemental reheater is used.

SECTION 4

RECOMMENDATIONS

Based on the results of this study, the following are recommended:

- (1) Future development of the exit gas recirculation reheat configuration should be considered, since it appears to be economically competitive with other reheat configurations and to have certain reliability advantages.
- (2) A study of the mechanisms resulting in the occurrence of acid rainout in the vicinity of the plant should be undertaken. A series of investigations at demonstration facilities are recommended to:
 - Study the mechanism of acid rainout occurrence as a function of climatic conditions, mist eliminator performance, stack velocity, and stack height.
 - Study the impact of different levels of reheat on the quantity of acid rainout as a function of climatic conditions. The results of this study should be compared with the impacts expected from other alternative measures for the prevention of acid rainout.
- (3) At a commercial power plant facility, a program should be initiated to determine the quantity of reheat required to protect downstream equipment. The theoretical energy required to prevent the occurrence of downstream condensation is the energy needed to keep the temperature of the flue gas above its dew point. However, industrial users usually specify higher levels (at least 30°F) of reheat to protect equipment; this indicates that other factors such as liquid droplet size, physical and chemical characteristics, and residence time (in the equipment downstream of the mist eliminator) should be considered in such an analysis.

SECTION 5

SURVEY OF CURRENT PRACTICE

As a part of this study, the state-of-the-art of stack gas reheat was investigated. Information was obtained from publications, electric utilities, architect/engineering (A/E) companies, and FGD system vendors using the following techniques.

- (1) A review of existing FGD literature sources
- (2) Circulation of a reheat questionnaire, approved by the Office of Management and Budget (OMB#158-578001), to 11 A/E firms, 7 FGD process vendors, and 46 electric utility companies. About 60 percent of the questionnaires distributed were returned. A copy of the questionnaire and a list of recipients are presented in Appendix B.
- (3) Telephone calls to clarify the information obtained in the questionnaire
- (4) Visits to three utility stations using various reheat configurations:
 - Kansas City Power and Light Company - La Cygne Station
 - Kansas Power and Light Company - Lawrence Energy Center
 - Public Service Company of Colorado - Cherokee Power Plant

LITERATURE REVIEW

The current state-of-the-art of stack gas reheat was reviewed as the initial phase of this study. The results of this review are presented and used throughout the report. As an introduction to the presentation of results of the OMB-approved questionnaire, a brief discussion is presented concerning reasons for using reheat, viable reheat configurations, and available forms (reheat media) of energy for reheat.

Reasons for Reheating Stack Gases

Stack gases from utility boilers without flue gas desulfurization (FGD) are normally exhausted at a temperature of 250 to 300°F. In this temperature range, the flue gas is relatively dry and noncorrosive. The wet FGD processes currently being used commercially in the United States cool the boiler flue gas from about 300°F to its adiabatic saturation temperature, normally 125-140°F. This saturated flue gas may cause the following problems:

- (1) The corrosion of equipment downstream of the scrubber due to the presence of moisture, acid, and chlorides
- (2) The occurrence of acid rainout in the vicinity of the plant stack
- (3) The formation of a visible plume which may be hazardous to ground and air traffic in the vicinity of the power plant
- (4) High ground-level pollutant concentrations downwind from the stack due to poor plume buoyancy

Reheating the saturated flue gas to a temperature above its saturation temperature will lessen the impacts of each of these four potential problems.

As the above discussion indicated, the need for reheating a scrubbed flue gas is dependent on the temperature and water content of the flue gas. These characteristics are, in turn, functions of the type of FGD process used. There are presently some 100 processes that have been conceived for the control of sulfur dioxide in flue gases. Of these processes, there are five that are in commercial use today in the United States. In addition, there are six that are currently at the demonstration level of development. Table 7 presents a brief characterization of these 11 FGD processes. These processes can be categorized as being dry or wet depending on the temperature and water vapor content of the treated gas.

TABLE 7. FGD PROCESS CHARACTERIZATION

Process	Development Status	Process Type	Approximate Flue Gas Temperature (°F)		Amount of Water Added
			Entering FGD Process	Exiting FGD Process	
Lime/Limestone	Commercialized	Wet	300	125-140	Saturates flue gas
Sodium Alkali	Commercialized	Wet	300	125-140	Saturates flue gas
Wellman-Lord	Commercialized	Wet	300	125-140	Saturates flue gas
Magnesium Oxide	Commercialized	Wet	300	125-140	Saturates flue gas
Sodium Scrubbing	Commercialized	Wet	300	125-140	Saturates flue gas
Spray Drying	Commercialized, no full scale data available at this time	Dry	300	1400	Adds some water but does not saturate
Citrate/Phosphate	60-HR demonstration underway	Wet	300	125-140	Saturates flue gas
Bergbau-Forschung/Foster Wheeler	20-HR demonstration completed	Dry	600	270-340	None
Atomics International/Aqueous Carbonate Process (Spray Dryer)	1,2-HR demonstration completed; 100-HR demonstration planned	Dry	300	1400	Adds some water but does not saturate
Shell/Inop	0.6-HR demonstration completed; 40-HR application in Japan	Dry	700-750	700-750	None
Chiyoda 121	20-HR demonstration completed	Wet	300	125-140	Saturates flue gas

Reproduced from
best available copy.

A wet FGD process saturates the flue gas with water vapor while cooling the gas to its adiabatic saturation temperature (normally in the range of 125-140°F). Dry processes do not saturate the flue gas with water vapor. Spray dryers (one type of dry system) cool the flue gas by adding water, although the gas temperature is maintained at least 10-15°F above the adiabatic saturation temperature. Some dry processes (such as Bergbau-Forschung) do not cool the flue gas. Flue gas exits these processes at temperatures greater than 250°F.

It is likely that reheat will not be used in conjunction with most dry FGD processes but may be required for wet scrubbing processes. Only wet processes were considered for reheat applications in this study. However, the techniques used to determine the need for and cost of stack gas reheat are applicable to dry FGD systems as well.

Reheat Configurations

Although reheating a saturated flue gas can be achieved by several methods, currently all methods heat the flue gas and raise its temperature before it enters the stack. Raising the flue gas temperature can eliminate or reduce the impact of the problems that may be caused by a wet saturated flue gas. The quantity of reheat needed is dependent on the specific problem which is to be resolved, the reheat method used, and other factors which are site-specific. Some of these factors are:

- (1) The quantity of entrained mist downstream of the scrubber
- (2) The quantity of heat lost from the system through the walls of the flue gas duct and plant stack
- (3) The position of the flue gas fan relative to the scrubber

The theoretical levels of reheat required to eliminate each of the potential problems associated with saturated flue gases are discussed in Section 6.

Several methods have been developed to reheat flue gases. Descriptions of those reheat methods that have been most extensively developed are presented below.

Inline Reheat--

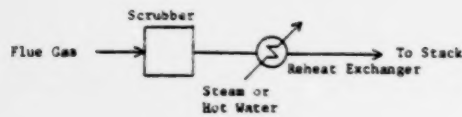
In this reheat scheme, an exchanger is placed directly in the duct work to heat the scrubbed flue gas. The heating medium can be either saturated or superheated steam or hot water. The advantages with this configuration are its simplicity of design and low energy consumption. However, this configuration typically exhibits poor operating reliability since the exchanger is exposed to highly corrosive wet flue gas. A schematic of this configuration is presented in Figure 2a.

Indirect Hot Air Injection Reheat--

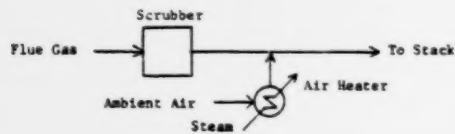
Ambient air is heated in an exchanger with steam or hot water and is then mixed with flue gas in order to raise the flue gas temperature. This reheat configuration exhibits better operating reliability than the inline method because the exchanger is not contacted by the corrosive flue gas. This method not only heats the flue gas but also dilutes it with ambient air. The dilution effect caused by the addition of air lowers the dew point of the scrubbed gas and lowers the pollutant concentrations exiting the stack. A drawback to the configuration is that more energy is required compared to inline reheat because heat is required to raise the temperature of both the flue gas and injected air to the desired stack temperature. A simplified schematic of indirect hot air reheat is presented in Figure 2b.

Direct Combustion Reheat--

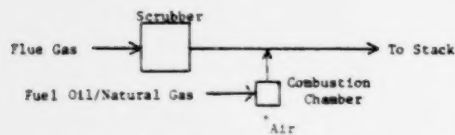
Direct combustion reheat mixes hot exhaust gases generated by firing fuel oil or natural gas with the flue gas in order to raise its temperature. Like indirect hot air reheat, this configuration exhibits good operating reliability. However, increasing fuel oil and natural gas costs and availability for power plant use are likely to limit the use of direct combustion



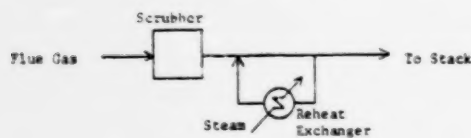
(a) Inline Reheat



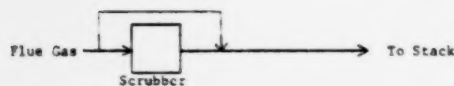
(b) Indirect Hot Air Reheat



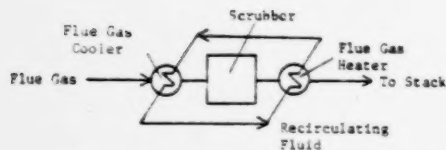
(c) Direct Combustion Reheat



(d) Exit Gas Recirculation Reheat



(e) Bypass Reheat



(f) Waste Heat Recovery Reheat

Note: Fans and pumps not shown for simplicity.

Figure 2. Simplified schematics of various reheat configurations.

reheat. Emission standards will also limit the use of reheat fuels containing sulfur. A schematic of this configuration is presented in Figure 2c.

Exit Gas Recirculation Reheat--

In this reheat configuration, a portion of the flue gas that has been scrubbed and reheated is routed to an exchanger where it is heated further. This heated flue gas is then mixed with saturated flue gas. This configuration seems to possess the best qualities of both the inline and the indirect hot air reheat configurations. Like the inline system, the energy supplied goes directly into heating the flue gas since the flue gas mass flow rate exiting the stack is not increased. Like indirect hot air reheating, the exchanger does not directly contact wet, saturated flue gas and this system should therefore exhibit good reliability. However, this configuration has not been commercially proven. A schematic of exit gas recirculation reheat is presented in Figure 2d.

Bypass Reheat--

In a bypass reheat system, a portion of the boiler flue gas is routed around the scrubber and mixed with the scrubbed flue gas. The initial investment and operating costs associated with this configuration are low compared to other reheat schemes. However, future use of this method is restricted by SO₂ emission standards. A simplified schematic of this reheat method is presented in Figure 2e.

Waste Heat Recovery (From Stack Gases With Temperature <300°F)--

This reheat method involves heating the scrubbed flue gas directly or indirectly (with a heating medium) with unscrubbed flue gas. There are several possible configurations for this type of reheat:

- (1) Bypass reheat
- (2) Ljungstrom heat exchangers (gas-gas heat exchanger)
- (3) Recirculating heating media (two gas-liquid heat exchangers)

Bypass reheat has been discussed earlier. The liquid-gas (Figure 2f) and gas-gas exchangers (Ljungstrom) have not been proven in commercial applications for stack gas reheat. The extremely corrosive conditions encountered when flue gas is cooled below the sulfuric acid dew point make the use of exchangers for waste heat recovery questionable on the basis of reliability. Results of ongoing commercial tests in Japan should be obtained and examined before pursuing the use of the Ljungstrom type exchanger for reheat applications.

Reheat Energy Media

In a power plant, there are many potential energy sources available as reheat media. Presented in Table 8 is a summary of the important reheat configurations and a listing of reheat media that could be used in each. In this report, extraction steam from a turbine for inline, indirect hot air, and exhaust recirculation, and fuel oil or natural gas for direct combustion will receive primary emphasis.

SURVEY RESULTS

Questionnaires were sent to FGD system users, vendors, and designers to determine how many of the reheat configurations identified in the literature survey have been used in commercial applications. For those configurations that had been used commercially, the purpose of the survey was to learn the design philosophy and operating history of each application. This information was then used to evaluate the feasibility, reliability and cost of each reheat configuration. The results obtained from the survey are discussed as follows:

- (1) Architect/engineering companies and FGD process vendor responses
- (2) Electric utility responses which include:

TABLE 8. REHEAT CONFIGURATIONS AND POTENTIAL ENERGY SOURCES

	Comments
<u>Inline and Exit Gas Recirculation</u>	
Throttle Steam	In heat exchanger
Extraction Steam	In heat exchanger
Hot Water	In heat exchanger
Flue Gas (before air preheater)	In heat exchanger
<u>Indirect Hot Air</u>	
Throttle Steam	In heat exchanger
Extraction Steam	In heat exchanger
Hot Water	In heat exchanger
Heated Air From Air Preheater	No exchanger needed
<u>Direct Combustion</u>	
Natural Gas	
Low Sulfur Fuel Oil	
<u>Waste Heat Recovery</u>	
Bypass*	Energy supplied from flue gas (temperature <300°F)
Ljungstrom (gas-gas)	
Recirculating Liquid	

*Either flue gas entering or exiting air preheater. Flue gas withdrawn for scrubber bypass prior to entering the air preheater would contain some recoverable energy. Therefore, it would not be considered as totally using waste heat.

- General information
- Inline reheat users
- Indirect hot air reheat users
- Direct combustion reheat users
- Bypass reheat users
- Wet stack users

These questionnaires were returned to Radian during the time period January, 1978 - July, 1978.

Architect/Engineering Company - FGD Process Vendor Responses

Of the 18 questionnaires distributed to A/E firms and FGD process vendors, 12 responses were returned. Ten companies indicated that they do not recommend reheat as a necessary part of a wet scrubbing system. Two companies always recommend reheat.

Table 9 presents the preferred reheat configurations (if reheat is specified by the client) of the A/E firms and vendors. Indirect hot air reheat is recommended most often because of its better reliability compared to an inline system. Bypass reheat is the most economical form, not only because it requires no additional energy source, but also because the scrubber size is smaller. However, many A/E firms felt that the proposed (promulgated in the June 11, 1979 Federal Register) SO₂ standards would severely restrict using bypass reheat. Some therefore did not specify it as a choice. (This information was gathered before the final utility boiler NSPS were promulgated in June 1979. The final standards do allow partial scrubbing of low sulfur coals).

Most firms did not recommend inline reheat because of reliability concerns. These include corrosion and plugging due to mist and solids carry-over. Direct combustion reheat has been used mainly for retrofit and test facilities where space was critical. Fuel oil or gas availability, while not a major problem for utilities currently using direct combustion, may be

TABLE 9. FGD PROCESS VENDOR- AND A/E-PREFERRED REHEAT SYSTEMS^a

Configuration	Number of Recommendations
Inline	3
Indirect (Hot Air)	10
Direct Combustion	1
Bypass	7
Exit Gas Recirculation	0
Waste Heat Recovery	0

^aAlthough 12 A/E companies and FGD process vendors responded, some firms recommended more than one form of reheat.

Other pertinent information contained in the A/E-vendor questionnaire responses is listed below:

- 1) Temperature drop from reheater exit to stack exit: ~5°F
- 2) Typical stack velocities: 40-90 ft/sec
- 3) Typical duct velocities: 50-70 ft/sec
- 4) Indirect hot air reheat systems should be designed with carbon steel or copper tubes with fins.
- 5) Inline reheat systems should be composed of bare tube exchangers. Recommended metals included carbon steel, stainless steels, and nickel alloys. Soot blowing is a recommended maintenance procedure.
- 6) Mist loadings downstream of the mist eliminators will probably be lower for clear liquor scrubbers compared to processes with slurry streams.
- 7) Steam was generally recommended over hot water as the reheat medium for inline and indirect hot air systems.

an important consideration for new facilities. Also, over the life of the plant, the fuel cost may become prohibitively expensive. Government policies, such as the "Powerplant and Industrial Fuel Use Act of 1978" may also have an important influence on the use of direct combustion reheat.

Electric Utility Responses

In this section, general information relating to overall industry practice is discussed. Details of individual company experience regarding each of the currently used reheat methods are also presented.

Table 10 lists the currently used or proposed stack treatment methods (wet stack, inline reheat, indirect hot air, etc.) for 103 scrubbing facilities. The selection of an SO₂ removal system and/or reheat system for 49 facilities is currently undecided. Information for this table was obtained via the survey and personal communications. Additional information was obtained from the FGD literature.

The total number of reheat configurations and their tentative startup dates are presented in Table 11. The table indicates a movement from reheating with energy sources other than the flue gas (inline, indirect hot air, and direct combustion) to bypass reheating and wet stacks. At the time these data were collected, it was unknown whether the final New Source Performance Standards (issued in June 11, 1979 Federal Register) would allow partial scrubbing and, therefore, bypass reheat.

At the time the survey and literature review were conducted for this report, no utility was using or planning a waste heat recovery system or an exit gas recirculation system. Note that the inline reheat system is selected more often than any other wet flue gas treatment method. This contrasts with the A/E and FGD process vendor recommendation. The simplicity, economics, and success of some inline reheat systems evidently makes the inline system a better choice for many utilities than the more reliable, but more expensive, indirect hot air reheat method.

TABLE 10. ELECTRIC UTILITY UNITS AND SPECIFIED TYPE OF REHEAT

Company	Plant	Start-up	Reheat System
Alabama Electric Co-op.	Tombigbee #2	6-78	Bypass
	#3	6-79	Bypass
Allegheny Power System	Pleasants #1	3-79	Bypass
	#2	3-80	Bypass
Arizona Elec. Power Co-op.	Apache #2	6-78	Wet Stack
	#3	4-79	Wet Stack
Arizona Public Service	Cholla #1	10-73	Inline
	#2	6-78	Inline
	#4	6-80	Inline
	Four Corners #1	Unknown	Undecided
	#2	Unknown	Undecided
	#3	Unknown	Undecided
Basin Elec. Power Co-op.	#4	Unknown	Undecided
	#5	Unknown	Undecided
	Antelope Valley #1	1981	Undecided
	#2	1983	Undecided
	Laramie River #1	4-80	Wet Stack
Big Rivers Elec. Co-op.	#2	10-80	Wet Stack
	#3	6-83	Wet Stack
	Reid #2	12-79	Indirect
Board of Municipal Utilities	#3	12-80	Indirect
	Sikeston Power Station	11-80	Wet Stack
Brazos Elec. Power Corp.	San Miguel #1	12-79	Wet Stack
Central Illinois Light Co.	Duck Creek #1	8-78	Wet Stack
	#2	1-82	Wet Stack
Central Illinois Public Serv.	Newton #1	11-79	Bypass, Inline
Central Maine Power Co.	Sears Island #1	11-86	Undecided
Cincinnati Gas and Elec.	East Bend #2	1-81	Undecided
Colorado Ute Elec. Ass.	Craig #1	3-79	Inline
	#2	3-79	Inline
Columbus and S. Ohio Elec.	Conesville #3	1-77	Wet Stack
	#6	10-78	Wet Stack
	Poston #5	1981	Undecided
	#6	1983	Undecided
Commonwealth Edison	Powerton #5	12-79	Inline
	Will County #1	2-72	Inline
Delmarva Power Co.	Delaware City #1,2,3	4-80	Direct
Detroit Edison Co.	St. Clair	5-76	Direct
Ducquesne Light	Elrama	10-75	Wet Stack
	Phillips	7-73	Wet Stack
East Kentucky Power Co-op.	Spurlock #2	3-80	Undecided
General Public Utilities	Coho #1	5-87	Undecided
	Seward #7	5-84	Undecided
Gulf Power Co.	Crist #4, #5	1978	Undecided
	Crist #6, #7	1980	Undecided
	Lansing Smith #1, #2	1980	Undecided
Hoosier Co-op.	Merom #1	1980	Undecided
	#2	1981	Undecided
Indianapolis Power & Light	Petersburg #3	10-77	Undecided
	#4	4-82	Undecided
Kansas City Power & Light	Hawthorn #3	11-72	Inline
	#4	8-72	Inline
	La Cygne #1	2-73	Inline

(continued)

TABLE 10 (continued).

Reproduced from
best available copy.

Company	Plant	Start-Up	Bypass System
Kansas Power and Light	Jeffery #1	9-75	Bypass
	#2	9-75	Bypass
	Lawrence #4	12-68	In-line
	#5	12-71	In-line
Kentucky Utilities	Green River #1, 2, 3	9-75	Indirect
Lakeland Utilities	McIntosh #1	10-81	Indecided
Louisville Gas and Elec	Dane Run #1	3-76	Direct
	#5	12-77	In-line
	#6	3-79	Direct
	Mill Creek #1	1-82	In-line
	#2	1-82	In-line
	#3	12-77	In-line
	#4	8-80	In-line
Minnesota Power and Light	Paddy's Run #6	4-73	Direct
	Clay Boswell #4	1980	Bypass
	Aurora	5-73	Wet Stack
Minnesota Power Corp	Milton Young #2	9-77	Bypass
Montana Power Co	Colstrip #1	10-75	In-line
	#2	7-76	In-line
	#3	7-82	In-line
	#4	7-82	In-line
Nevada Power	Harry Allen #1	9-85	Undecided
	#2	9-84	Undecided
	#3	9-85	Undecided
	#4	9-86	Undecided
	Raid Gardner #1	1-75	Indirect
	#2	1-75	Indirect
	#3	1-75	Indirect
	#4	Unknown	Undecided
	Warner Valley #1	7-82	Undecided
	#2	9-83	Undecided
New England Elec Sys	Brayton Point #1	Unknown	Undecided
Niagara Mohawk Power Corp	Huntley #6	9-78	Undecided
Northern Indiana Public Service	Bailly #7	Unknown	Undecided
	#8	Unknown	Undecided
	D.H. Mitchell #11	9-77	Wet Stack (Direct available)
Northern States Power Co	Sherburne Co #1	1-76	In-line
	#2	1-77	In-line
	#3	1-81	Undecided
	#4	1-82	Undecided
Otter Tail Power Co	Covate #1	1-81	Dry Scrubber
Pacific Gas and Electric	Fossil #1	1984	Undecided
	#2	1985	Undecided
Pacific Power and Light	Jim Bridger #4	9-79	Wet Stack
	Dave Johnston	4-73	Wet Stack
Pennsylvania Power Co	Bruce Mansfield #1	4-76	Direct
	#2	4-77	Direct
	#3	4-80	Direct
Philadelphia Elec Co	Cromby	9-80	Undecided
	Eddystone #1A	7-75	Direct
	#1B	9-80	Direct
	#1C	Unknown	Direct
	#2	9-80	Undecided

(continued)

TABLE 10 (continued).

Company	Plant	Start-up	Reheat System
Potomac Elec. and Power	Dickerson #1	1979	Bypass
	#2	1979	Bypass
	#4	5-85	Undecided
Power Authority of New York	Arthur Kill	9-82	Undecided
Public Service-Colorado	Arapahoe #4	9-73	Inline
	Cherokee #1	9-73	Inline
	#3	11-71	Inline
	#4	7-74	Indirect
	Walmont #5	11-71	Inline
Public Service-New Mexico	San Juan #1	11-77	Indirect
	#2	11-77	Indirect
	#3	1-79	Undecided
	#4	5-81	Undecided
Public Service-Indiana	Gibson #5	1982	Undecided
Salt River Project	Coronado #1	4-79	Bypass
	#2	4-80	Bypass
	#3	1987	Undecided
South Carolina Public Service	Winyah #1	7-77	Bypass
	#3	1980	Bypass
Southern Illinois Power Co.-op	Marion #4	9-78	Wet Stack
Southern Indiana Gas and Elec.	AB Brown #1	4-79	Wet Stack
S. Mississippi Elec.	R. D. Morrow #1	2-78	Bypass
	#2	3-78	Bypass
Springfield City Utilities	Southwest #1	4-77	Wet Stack
Springfield Water Light & Power	Dallman #3	7-80	Bypass
Tennessee Valley Authority	Shawnee #10A	4-72	Direct
	#10B	4-72	Direct
	Widows Creek #7	Unknown	Inline
	#8	5-77	Indirect
Texas Municipal Public Agency	Gibbons Creek #1	3-78	Inline
Texas Power and Light	Sandow #4	7-80	Bypass
	Twin Oaks #1	8-80	Undecided
	#2	9-84	Undecided
Texas Utilities Co.	Forest Grove #1	1959	Undecided
	Martin Lake #1	10-77	Bypass
	#2	1-78	Bypass
	#3	12-78	Bypass
	#4	11-82	Undecided
	Monticello #3	1-78	Inline
United Power Assoc.	Coal Creek #1	11-78	Bypass
	#2	11-79	Bypass
Utah Power and Light	Emery #1	1-79	Indirect
	Huntington #1	3-73	Indirect
	Emery #2	6-80	Indirect
Virginia Electric and Power Co.	Mc. Storm	Unknown	Undecided
Wisconsin Power and Light	Columbia #2	1-80	Bypass

Note: Wet stack denotes the emission of a saturated flue gas with no reheat being used.
 Direct denotes direct combustion reheat. Data are current as of June 1979.
 Sources: Personal communication with utility.
 Questionnaire response.
 References 1 through 17.

TABLE 11. STARTUP DATES FOR VARIOUS REHEAT SYSTEMS

Startup	Inline	Indirect Hot Air	Direct Combustion	Bypass	Wet Stack
1968	1				
1969					
1970					
1971	2				
1972	4		2		1
1973	4		1		2
1974		3			
1975	1	1	1		1
1976	2	1	3		
1977	3	4	1	3	3
1978	3	2		7	4
1979	4	1	1	8	4
1980	3	2	3	7	3
1981	2				
1982	1				1
1983					1
Total for 1968-1977	17	9	8	3	7
Total for 1978-1983	13	5	4	22	13
Total for All Years	30	14	12	25	20

Table 12 was developed from information provided by electric utilities that responded to the questionnaire and from the literature survey. It shows that the operating plants which use reheat typically use more than 30°F as a reheat temperature criterion. In general, the overriding reason given by most utilities for using reheat was for equipment protection against corrosion. Enhanced plume rise was the second most numerous reason given for using reheat.

TABLE 12. REHEAT TEMPERATURE LEVELS AT OPERATING AND PLANNED UNITS*

ΔT (°F)	Operating Units	Planned Units
<20°F	1	3
20-40°F	1	4
40-60°F	8	1
60-100°F	1	2
>100°F	2	0

*This is the reheat level (stack exit temperature minus scrubber exit temperature) for reheat systems for which this information is known.

Sources of energy for reheat include steam, hot water, natural gas, fuel oil, and bypassed flue gas. The information obtained from the utility industry survey indicated the following breakdown of energy sources:

- (1) Inline reheat
 - 80 percent use steam
 - 20 percent use hot water
- (2) Indirect hot air injection reheat - all use steam
- 3) Direct combustion reheat
 - 35 percent use natural gas
 - 65 percent use fuel oil
- (4) Bypass reheat - uses heat in unscrubbed flue gas

No survey responses indicated any serious energy availability problems. Some retrofit units had to use throttle steam because extraction steam from the turbine was not available in sufficient quantities to provide the desired reheat level. Table 13 presents the number of responses relating to reheat media. Different units at the same plant were counted separately in determining these values.

TABLE 13. REHEAT ENERGY SOURCES

Energy Source	Inline Reheat	Indirect Hot Air Reheat	Direct Combustion Reheat
Steam	14	9	-
Hot Water	4	-	-
Gas	-	-	4
Fuel Oil	-	-	7

In the following sections electric utility experience, as determined from the survey for each type of reheat system, is summarized. Additionally, the use of wet stacks is discussed. The system descriptions do not incorporate experience since early 1978.

Inline Reheat--

Parameters affecting performance--Inline reheat is perhaps the simplest reheat configuration. Basically, hot elements (tubes or plates) are placed in the scrubbed gas stream. Forced convection heating from the hot surface to the flue gas occurs. Steam or hot water can be used as the heating medium.

In most cases the problems encountered by inline reheaters are caused by direct contact with the wet flue gas. Several factors can influence these problems. These include mist eliminator performance, flue gas chloride level, SO₂ and SO₃ concentrations, and the particulate loading. Additional factors which affect the reliability of the system include tube metallurgy and the reheat medium.

The major problem encountered is corrosion of the exchanger tubes. Corrosion may be caused by several mechanisms. One of the most common is acid attack. Data from several plants have shown that installations using high sulfur coals have experienced greater acid problems. The La Cygne and Lawrence power plants illustrate this trend. La Cygne burns a local coal with 5.3 percent sulfur and has experienced severe acid corrosion problems. Lawrence Unit #5 burns a 0.5 percent sulfur coal and has had very few corrosion problems in the last five years with its carbon steel tubes.

Coals generally contain chlorides which form hydrochloric acid following combustion. This acid is easily scrubbed out and, being a soluble species, the chloride ion remains in the scrubbing liquor. In closed-loop scrubbing systems, concentrations can reach several thousand ppm. If the mist eliminator does not remove the entrained slurry droplets, they will impinge on the hot surface of the reheater tubes. Here evaporation and chloride concentration occurs. The chloride ion acts on the metal surface causing stress corrosion and eventual failure. Systems with low chloride coal or that operate open-loop generally do not have stress corrosion problems.

Inline reheaters have experienced erosion and plugging of the reheater tubes. Fly ash is very abrasive on the reheater surfaces. Plugging occurs from slurry carry-over and subsequent deposition. In some cases, the deposited fly ash and unreacted alkali can remove SO_2 from the flue gas. Plugging is intensified by sulfite oxidation resulting in gypsum scale formation. In installations where plugging has occurred, various methods have alleviated the problem. Wider tube spacing, along with square (in-line) rather than triangular-pitched (staggered) tubes reduce plugging. Some reheat users have also replaced finned tubes with bare tubes in order to avoid these problems. Soot blowers are also used at most installations; the frequency of blowing ranges up to three times a shift.

Based on the survey responses, the two predominate materials specified for inline reheat exchangers are carbon steel and stainless steel type 316 (316SS). At the present time, there is not sufficient information to correlate material with tube service life. The variables discussed previously, such as coal composition, exchanger dimensions, and maintenance procedures, appear to have a major impact on tube life. Utility usage of more corrosion resistant metals is increasing. However, there are not enough results from inline reheat users to quantitatively determine the economic value of these generally higher-priced alloys.

The reheat medium used also influences the reliability of an inline reheater. Superheated steam, saturated steam, and hot water can all be used in an inline reheater. In extreme cases, the drop in degrees of steam superheat can be 300-400°F and can occur over a short portion of tubing. To avoid problems, braces are installed across the tube bundle which permit longitudinal expansion but eliminate lateral vibrations. Saturated steam will not have a temperature drop because only a phase change occurs. Hot water is also a readily available heating medium in a utility plant. Most installations using hot water circulate it from the deaerator. Three installations using hot water have experienced excellent tube life. However, long tube life and low corrosion may be more dependent on burning low sulfur and low chloride content coal than using hot water. Both stations (Lawrence and Sherburne) using hot water burn 1.0 percent or less sulfur coal.

The startup and shutdown procedures for an inline reheater are influenced by several factors, the most important being the prevention of condensation on and corrosion of the reheater tubes. This is usually accomplished by introducing steam to the reheater before it is contacted with the wet flue gas and keeping steam in the exchanger after the scrubber is shut down.

Inline installations--The use of inline reheat at eight facilities is discussed below. Table 14 presents information gathered for each system.

TABLE 14. INLINE REHEAT SYSTEMS

Company Unit	Arizona Public Service Cholla Unit #1	Commonwealth Edison Will County Unit #1
Reason for Reheat	Equipment protection	Equipment protection
Reason for Inline	None given	Economics
Boiler Size (MW)	115	136
Coal		
Type	New Mexico	Western
Sulfur (percent)	0.5	0.5
Heating Value (Btu/lb)	10,200	9,000
Scrubbing System	Limestone (Research Cottrell)	Limestone (BSW)
Start-up Date	October, 1973	February, 1972
Scrubbed Flue Gas		
Flow (acfm)	490,000	707,000
Temperature (°F)	120	123
SO ₂ Concentration (ppm)	100	500
Heating Medium		
Type	Steam	Throttle steam
Pressure (psig)	250	350
Temperature (°F)	400	485
Flow Rate (lb/hr)	20,000	60,000
Heat Exchanger		
Tube Size	1" OD	5/8" OD, .065" wall
Tube Length	--	11.5 feet
Tubes per Bundle	--	32
Bundles per Module	2	27
Tube Material	316LSS	316LSS and Carbon steel
Tube Life	--	12-15 months
Soot Blowers	Steam, 3/bundle, every 8 hrs	Every 4 hours
Ductwork	Carbon Steel/Ceilecote	--
Corrosion	Yes	--
Stack	--	Steel w/brick liner
Corrosion	--	None observed
Reheat ΔT (°F)	40	60-80
Fan Position (relative to scrubber)	Upstream	Downstream
Atmospheric Effects		
Mist	--	No
Acid Rainout	--	No
Fog	--	No
Comments	Vibrations have caused tube failure in the past. Baffles were installed which alleviated the problem.	Acid corrosion prompted use of 316LSS on lower tubes in banks. Pinhole corrosion usually occurs. Tubes kept hot during outages for longer life.
Source or Reference	P,1,2,12	P,Q,1,2,12

--No information available
P - Personal communication
Q - Questionnaire response

TABLE 14 (continued).

Company Unit	Northern States Power Co. Sherburne County Unit #1	Public Service Co. of Colorado Cherokee Unit #1
Reason for Reheat	Equipment protection	Equipment protection, plume buoyancy
Reason for Inline	Original design	Original design
Boiler Size (MW)	710	120
Coal		
Type	Montana	Colorado
Sulfur (percent)	0.8	0.5
Heating Value (Btu/lb)	9300	9500
Scrubbing System	Limestone (CE)	Particulate - TCA (COP)
Start-up Date	3-76	6-73
Scrubbed Flue Gas		
Flow (acfm)	2,240,000	402,000
Temperature (°F)	130	100
SO ₂ Concentration (ppm)	150-250	425
Heating Medium		
Type	Hot water	Steam
Pressure (psig)	60	300
Temperature (°F)	350 in - 230 out	420
Flow Rate (lb/hr)	2300 (gpm-circulated)	18,000
Heat Exchanger		
Tube Size	1 3/4" OD Finned	5/8" OD
Tubes per Bundle	45	--
Bundles per Module	4	3
Tube Material	Carbon steel	316SS
Tube Life	--	--
Soot Blowers	3 steam blowers, once a shift	Not used
Ductwork	Carbon steel	Carbon steel
Corrosion	No	Yes, when no reheat
Stack	Corten/liner	Concrete
Corrosion	No	Yes, when no reheat
Reheat ΔT (°F)	40	50
Fan Position (relative to scrubber)	Downstream	Upstream
Atmospheric Effects		
Mist	No	Yes, only on cold days with high humidity
Acid Rainout	No	No
Fog	No	No
Comments	No noticeable condensation or serious corrosion occurring. Slight plugging occasionally.	Originally had finned tubes which plugged and corroded. Bare tubes stay clean, do not require soot blowing.
Source or Reference	P,Q,12	P,1,11

--No information available

P - Personal communication

Q - Questionnaire response

TABLE 14 (continued).

Company Unit	Kansas City Power and Light Hawthorne Unit #3	Kansas City Power and Light LaCygne Unit #1
Reason for Reheat	Equipment protection	Equipment protection, plume rise
Reason for Inline	Original design	Original design
Boiler Size (MW)	100	820
Coal		
Type	Oklahoma	Kansas
Sulfur (percent)	3.0	5.3
Heating Value (Btu/lb)	12,000	9,300
Scrubbing System	Lime (CE)	Limestone (B & W)
Start-up Date	11-72	2-73
Scrubbed Flue Gas		
Flow (acfm)	306,000	2,460,000
Temperature (°F)	122	122
SO ₂ Concentration (ppm)	100-600	1,200
Heating Medium		
Type	Steam	Extraction steam
Pressure (psig)	--	150
Temperature (°F)	--	650
Flow Rate (lb/hr)	--	60,000
Heat Exchanger		
Tube Size	1" OD Finned	5/8" OD, .12" wall*
Tube Length	--	30'
Tubes per Bundle	--	24
Bundles per Module	1	16 (32 in two modules)
Tube Material	Carbon steel	Desensitized 316LSS
Tube Life	>5 years	3 - 3-1/2 years
Soot Blowers	Steam	Steam, 4 per module, once per 8 hour shift
Ductwork	--	Carbon steel/Plascite 4005-5
Corrosion	--	Occurs if gas is wet - recoat every 2 years
Stack	--	Carbon steel/Plascite
Corrosion	--	--
Reheat ΔT (°F)	50	25 (50 in 3 of 3 modules)
Fan Position (relative to scrubber)	Downstream	Downstream
Atmospheric Effects		
Mist	No	Yes, has been occasionally experienced
Acid Rainout	No	Yes, car paint damage noticed
Fog	No	Yes, infrequent
Comments	Plugging has been a greater problem than corrosion. Modules are shutdown every three days for overall cleaning.	High SO ₂ and ash levels have caused 304SS, CS, 316SS tubes to fail. Careful cleaning and elimination of mechanical vibration was key to recent success. Reheat 30°F in all modules is desired; however, piping limited at present.
Source or Reference	P.1,2,12	

*Module #8 has 1"OD tubes x 30'x.12" wall - 3 bundles due to scrubber configuration.

--No information available
P - Personal communication

TABLE 14 (continued).

Company Unit	Kansas Power and Light Lawrence Unit #5	Montana Power Co. Colstrip Unit #1
Reason for Reheat	Equipment protection	Equipment protection
Reason for Inline	Original design	Economics & performance
Boiler Size (MW)	400	360
Coal		
Type	S.E. Wyoming	Montana - sub-bituminous
Sulfur (percent)	0.5	0.8 (avg.)
Heating Value (Btu/lb)	10,000	8,550
Scrubbing System	Limestone (CE)	Lime, fly ash (ADL-CEA)
Scrubbed Flue Gas		
Flow (acfm)	636,000	--
Temperature (°F)	120	--
SO ₂ Concentration (ppm)	100-500	--
Heating Medium		
Type	Hot water	Steam
Pressure (psig)	200	150
Temperature (°F)	250 in - 180 out	360
Flow Rate (lb/hr)	--	--
Heat Exchanger		
Tube Size	1 3/4" OD, 3/4" Fins	Not applicable
Tubes per Bundle	64	11 panels per bank
Bundles per Module	4	2 sections, 6 banks each
Tube Material	Carbon steel	Top-Inconel 625, Bottom-Hastelloy G (one in each of three modules)
Tube Life	6-10 years	--
Soot Blowers	250 psig air - twice per shift	4 per module
Ductwork	--	--
Corrosion	--	No
Stack	Steel/gunnite	--
Corrosion	--	No
Reheat ΔT (°F)	30	50
Fan Position (relative to scrubber)	Downstream	Downstream
Atmospheric Effects		
Mist	No	--
Acid Rainout	No	--
Fog	No	--
Comments	Low SO ₂ , SO ₃ , chloride and ash levels important to long tube life.	No corrosion of plate coil. Plugging occurred once after a temperature excursion and subsequent mist eliminator failure.
Source or Reference	P,1,2,12	P,12

Cholla Unit #1--Arizona Public Service: This unit has experienced corrosion caused by condensation and subsequent dilute sulfurous acid formation. This resulted from the design which allowed condensate to collect in stagnant pockets. The Corten expansion joints were most affected. Insulation of the ducts and replacement of the Corten with rubber liners helped stop the corrosion.

Tube vibrations occurred due to the constriction of the gas flow in the reheater. Baffles were installed which eliminated this problem. Some stress corrosion due to chloride attack has been noticed on the stainless steel tubes.

Will County Unit #1--Commonwealth Edison: Corrosion of the lower tube banks occurred and prompted the use of 316SS for the lower tube bundles of the reheater. The tubes are kept hot even when the scrubber is off line to prevent acid attack. A high reheat temperature is used to prevent damage to the induced draft fan. The fan is washed and inspected during each outage. Reheater tube failure has caused a shutdown three times in the past two years. The tube bundles are either patched, blanked off, or replaced during the outages.

Hawthorne Units #3 and #4--Kansas City Power and Light: The Hawthorne Units 3 and 4 originally used hot water as the reheat medium. During an outage in 1977, the system was modified to use steam. This produced higher reheat temperatures and better plume buoyancy. Erosion and plugging of the finned carbon steel tubes has been a greater problem than corrosion. As the old tubes fail after eight years of service, they are being replaced by 316SS tubes. These tubes are on a square pitch (inline) rather than triangular (staggered). The utility feels this arrangement will alleviate some plugging problems.

La Cygne Unit #1--Kansas City Power and Light: Inline reheat problems at LaCygne are probably as severe as any utility location. The local coal is high in sulfur and ash. The scrubber is used for both particulate and SO₂ control; consequently, the entrained slurry is both abrasive and corrosive. Approximately 50-60 ppm of SO₃ has been detected downstream of the scrubber. The original 304SS tubes failed within six months of startup. Replacement carbon steel tubes lasted nine months. Desensitized 316SS tubes were then used and lasted 12-15 months.

After the 316SS tubes failed, ducts from the air preheater were installed to deliver hot air to the scrubbed flue gas. About 15-17 percent of the heated air was mixed with the flue gas. This method limited the boiler output and was discontinued. The ducts were not removed, and at present, about two percent of the preheated air mixes with the scrubbed gas.

Presently, thick wall tubes of desensitized 316SS are in use. They have been in operation three to three and one-half years. Braces on each bundle prevent harmonic vibrations. The tubes are washed as soon as a module is taken out of service to remove deposits. Soot blowers are used once a shift. The utility feels that continued improvement in mist eliminator performance and preventive maintenance will extend tube life considerably.

Three of the eight modules can reheat 50°F. The other five reheat 25°F. The downstream I.D. fans contribute 15-20°F of reheat to the gas. Even at these reheat temperature ranges, mist, acid rainout, and fog have occasionally been experienced. The stack has a carbon steel liner coated with plasite. This coating is reapplied every two years. There is not a stress corrosion problem because the chloride level in the coal is rather low.

Lawrence Unit #5--Kansas Power and Light: Unit #5 uses a venturi-absorber system for both particulate and SO₂ control. A low sulfur, low

ash Wyoming coal is burned and inline finned carbon steel tubes are used for reheat to protect the I.D. fan and stack. Hot water (250°F) from the deaerator is used for heating. The original tubes had copper fins which flattened under the soot blower pressure. Plugging was also a problem. Redesign of the mist eliminator helped reduce the plugging significantly. Carbon steel fins were installed and have operated satisfactorily for more than six years. Soot blowers, using compressed air, are operated twice a shift. After 18 months of service, the tubes on Unit #5 have not required any service. The utility feels that low sulfur, chloride and ash levels in their coal are responsible for the long tube life. This utility would probably use inline finned tubes on a new unit burning the same type coal.

Colstrip Unit #1--Montana Power Company: The Colstrip units are unique in that they are the first units to use plate coils for reheat rather than tube bundles. Reheat is used to protect the induced draft fan and stack. Each module has two reheat sections and each section has six banks. Each bank is composed of 11 plate coil panels. The bottom section is made of Hastelloy C and the top section is Inconel 625.

There are four soot blowers per module and the pressure drop across the reheaters is 2 to 3 inches of water. To date, there have been no serious plugging problems and no corrosion has occurred.

Sherburne County Unit #1--Northern States Power Company: The inline finned tubes at Sherburne County use hot water to protect the I.D. fan and stack and to improve plume dispersion. Hot water is circulated from the deaerator. Soot blowers are used once a shift. No other special maintenance is employed for the reheater. Some corrosion has occurred, although it has not been very serious. The boiler burns a low sulfur Western coal.

Cherokee Unit #1--Public Service of Colorado: The Cherokee units use three-stage turbulent contact absorbers for particulate removal. The original reheater consisted of one bare and two finned banks of carbon steel

tubes. After two years of continual plugging, they were replaced with 316SS bare tubes. These tubes stay clean and do not require soot blowing. They are inspected during every outage and have not shown any problems.

During periods when reheat was not used, corrosion in the ducts and stack occurred. Mist has been observed during cold weather at high humidity; however, most of this mist is generated by nearby cooling towers.

Indirect Hot Air Injection Reheat--

Parameters affecting performance--Indirect reheat involves heating air with steam and mixing the heated air with the wet flue gas. It differs from inline reheat in that the heat exchanger surface does not contact the wet flue gas. Consequently, this system exhibits a better reliability than the inline configuration because corrosion and plugging are less likely. A greater volume of gas must be handled through the ducts and stack with indirect reheat due to the air injected. This may have an adverse effect on an existing primary fan in retrofit situations. Also, when reheating to the same stack temperature, indirect reheat requires significantly more energy than inline reheat. This extra energy is required to heat the added air from ambient conditions to the stack temperature. In general, the capital and operating costs of indirect systems are higher than inline but have been justified by some utilities because of longer exchanger life and better reliability.

Mixing of the hot air with the flue gas must be successfully accomplished to prevent hot spots on the duct walls. This can be done with injection nozzles, or merging ducts. It is also important to protect the duct walls from overheating during startup and shutdown. This can be done by bringing the scrubber on stream before the air heater and shutting down the air heater before the scrubber. A small air flow across the tubes is advised until the corrosive saturated flue gas is purged from the ductwork during outages. The majority of the reheaters use carbon steel tubes. Some

corrosion has occurred due to flue gas in-leakage; however, with proper design and operating practice it appears that stainless steels and other alloys are not required.

Indirect hot air installations--Of the 13 planned and operating indirect systems, five were selected for discussion. They are Reid Gardner Unit #1--Nevada Power Company, Cherokee Unit #4--Public Service Company of Colorado, Widow's Creek Unit #8--Tennessee Valley Authority, Green River--Kentucky Utilities, and Huntington Unit #1--Utah Power and Light. Table 15 presents summary information for four of these installations.

Reid Gardner Unit #1--Nevada Power Company: All three Reid Gardner scrubbers use sodium carbonate scrubbing and indirect hot air reheat. Carbon steel finned tubes are used to heat air to approximately 490°F which is then mixed with the scrubbed gas. In four years of service, no significant problems have occurred. The reheater is placed in service after the scrubber is online. It is removed from service before the scrubber is shut down. This avoids any thermal damage to the duct lining.

Cherokee Unit #4--Public Service Company of Colorado: Experiences with inline reheat at Cherokee Units #1 and #3 and the Valmont and Arapaho stations prompted the use of indirect reheating at Cherokee Unit #4. The utility has found that the indirect system requires more maintenance than the inline system. This is due to the forced draft fan configuration (primary fan) which occasionally forces flue gas into the hot air ducts. The original carbon steel finned tubes have corroded due to this flue gas infiltration. New finned tubes will be made of stainless steel. The air flow rate is between 40 and 50 percent of the flue gas rate. It was found that indirect hot air reheat requires more steam than inline reheat to get the same outlet stack temperature. In another installation the utility has indicated that if reheat were selected, inline reheat would be used rather than indirect hot air because of the high maintenance and operating costs (related to steam use) they have now experienced with indirect systems.



TABLE 15. INDIRECT HOT AIR REHEAT SYSTEMS

Company Unit	Nevada Power Company Reid Gardner Unit #1	Public Service Company of Colorado - Cherokee Unit #4
Reason for Reheat	Equipment protection	Equipment protection
Reason for Indirect	Better reliability	Problems with inline reheat on Units 1 and 2
Boiler Size (MW)	115	370
Coal		
Type	--	Colorado
Sulfur (percent)	0.5	0.5
Heating Value (Btu/lb)	12,500	9,500
Scrubbing System	Sodium carbonate (ADL/CEA)	Particulate - TCA (UOP)
Start-up Date	4-74	7-74
Scrubbed Flue Gas		
Flow (acfm)	443,000	1,210,000
Temperature (°F)	119	100
SO ₂ Concentration (ppm)	50	425
Heating Medium		
Type	Steam	Steam
Pressure (psig)	450	600
Temperature (°F)	760	436
Flow Rate (lb/hr)	30,000	50,000
Air		
Flow (acfm)	67,000	196,000
Outlet Temperature (°F)	490	440
Heat Exchanger		
Tube Size	5/8" OD Finned, .014" wall	5/8" OD Finned
Tube Length	10'	--
Tubes per Bundle	65	--
Bundles per Module	6	2
Tube Material	Carbon steel	Carbon steel
Corrosion	None	Some due to backmixing
Ductwork	Carbon steel/liner	Carbon steel
Corrosion	--	Yes
Stack	Concrete/Brick liner	Concrete
Corrosion	--	Yes
Reheat ΔT (°F)	23-25	40-50
Fan Position (relative to scrubber)	Upstream	Upstream
Atmospheric Effects		
Mist	No	Yes, when no reheat
Acid Rainout	No	No
Fog	No	No
Comments	No problems after 4 years of operation	More maintenance required than for inline reheat
Source or Reference	P.O., 1.13.19	P. 1.1.11

--No information available
P - Personal communication
Q - Questionnaire response

TABLE 15 (continued).

Company Unit	Tennessee Valley Authority Widow's Creek Unit #8	Utah Power and Light Huntington Unit #1
Reason for Reheat	Equipment protection, plume dispersion	Equipment protection, plume rise
Reason for Indirect	At time of installation most reliable type of reheat	Reliability
Boiler Size (MW)	550	400
Coal		
Type	Mix (AL,TN,KY)	Bituminous - Utah
Sulfur (percent)	2.3	0.53
Heating Value (Btu/lb)	10,920	12,000-12,500
Scrubbing System	Limestone (TVA)	Lime (spray tower)
Start-up Date	5-77	5-79
Scrubbed Flue Gas		
Flow (acfm)	1,400,000	--
Temperature (°F)	125	119
SO ₂ Concentration (ppm)	200-500	300-400
Heating Medium		
Type	Extraction steam	Extraction steam
Pressure (psig)	500	275
Temperature (°F)	650	600
Flow Rate (lb/hr)	160,000	--
Air		
Flow (acfm)	120,000	--
Outlet Temperature (°F)	400	300
Heat Exchanger		
Tube Size	5/8" OD, 8 Fins/inch	Finned
Tubes per Bundle	40	--
Bundles per Module	2	--
Tube Material	Carbon steel/copper fins	Carbon steel
Corrosion	none	
Ductwork	Corten	Carbon steel/precast liner
Corrosion	--	--
Stack	Reinforced concrete/brick liner	Acid brick
Corrosion	--	--
Reheat ΔT (°F)	50	20
Fan Position (relative to scrubber)	Upstream	Upstream
Atmospheric Effects		
Mist	No	No
Acid Rainout	No	No
Fog	No	No
Comments	TVA will use inline on Widow's Creek #7 because capital cost is less and most operating problems have been reduced.	In operation only about 3 mo. Used bypass reheat most of the time.
Source or Reference	P.O.2	P.O

--No information available

P - Personal communication

Q - Questionnaire response

Widow's Creek Unit #8--Tennessee Valley Authority: The terrain and local meteorological conditions around the plant eliminate the possibility of using a wet stack. Reheat is used to enhance plume dispersion which is necessary for acceptable ground-level pollutant concentrations. TVA selected indirect hot air reheat because of problems they experienced with the inline configuration. However, in Widow's Creek Unit #7, TVA will try inline reheat because it is felt that the earlier problems have been minimized by a better mist eliminator design and improved maintenance procedures. TVA has observed that the capital and operating costs for the indirect hot air systems are higher than those for an inline reheater. No operating problems have occurred with the indirect system at Widow's Creek.

Green River--Kentucky Utilities: The Green River scrubber was started up in September 1975 with a wet stack. In February, 1977 the Carboline lining in the stack was replaced due to failure. Substantial damage to the paint on parked cars was also encountered at this facility. In an attempt to eliminate these problems, Kentucky Utilities decided to install an indirect hot air system to raise the flue gas temperature 50°F. The Carboline lining was removed and replaced with Precrete over a wire mesh.

Direct Combustion Reheat--

Factors affecting performance--Direct combustion of oil or gas is one of the simplest forms of reheat. Combustion can occur either in an internal or external chamber with a refractory lining. Startup must be accomplished slowly to prevent damage to the refractory lining. Since fuel oil combustion in an internal chamber can produce flame instability and incomplete combustion, most oil burning sites use external combustion chambers. A small fan for combustion air is also required. Gas systems have greater flame stability and may be used directly in the flue gas stream as oxygen in the flue gas is available to support combustion.

A definite advantage of direct combustion reheat is its limited space requirements. Compared to the tube bundles and duct work of the other systems, its size is more conducive to retrofit installations. Also, the capital investment for the burners and refractory materials is small compared with other systems. Since low sulfur fuel is required for this reheat process in order to satisfy SO₂ emission regulations, the availability and cost of such a fuel may limit the use of this configuration. The impact of government legislation, such as the "Powerplant and Industrial Fuel Use Act of 1978" may also affect the applications of direct combustion for reheat, although no user response indicated availability problems at the time these responses were returned.

The "Powerplant and Industrial Fuel Use Act of 1978" prohibits the use of oil and gas as primary fuel in new power plants unless specific exemptions are granted. While there is no specific prohibition of the use of these fuels as a stack gas reheat energy source, the use of steam and hot water generated from the firing of coal will probably be encouraged by regulatory agencies.

Direct combustion installations--Four systems which use direct combustion reheat are discussed below. Three of the facilities use oil and one uses natural gas. Table 16 presents summary information on these four units. Other direct combustion reheat units are also mentioned.

Cane Run Unit #4--Louisville Gas and Electric: This boiler has been retrofitted with an FGD system. Direct combustion reheat was selected because it was the easiest to retrofit and a fuel oil tank was available at the plant. Operation has been good; however, some trouble has been experienced with an uneven temperature profile resulting in overheated ducts. The temperature of the combustion gases is about 900°F prior to mixing with the flue gas.



TABLE 16. DIRECT COMBUSTION REHEAT SYSTEMS

Company Unit	Louisville Gas and Electric Cane Run Unit #4	Louisville Gas and Electric Peabody's Run Unit #6
Reason for Reheat	Equipment protection	Equipment protection
Reason for Direct	Easiest to retrofit	Easiest to retrofit
Boiler Size (MW)	178	65
Coal		
Type	Peabody	Peabody
Sulfur (percent)	3.5	3.7
Heating value (Btu/lb)	10,800	10,800
Scrubbing System	Line (AAF)	Line (CE)
Start-up Date	8-76	4-73
Scrubbed Flue Gas		
Flow (acfm)	735,000	250,000
Temperature (°F)	125	126
SO ₂ Concentration (ppm)	200	150
Fuel and Combustion		
Combustion Chamber	--	Internal
Fuel Type	#2 fuel oil	Gas
Fuel Rate	72 (gph)	20,000 (scfh)
Ductwork	Steel/Plascrete 4065	Mild steel
Corrosion	None	--
Stack	Concrete/Precrete	Concrete/Precrete
Corrosion	--	--
Reheat ΔT (°F)	35-40	45-55
Fan Position (relative to scrubber)	Upstream	Downstream
Atmospheric Effects		
Mist	No	No
Acid Rainout	No	No
Fog	No	No
Comments	Duct walls have overheated at times	Excellent service for over 4½ years
Source or Reference	P,Q,2	Q,1,2,12,19

--No information available

P = Personal communication

Q = Questionnaire response

TABLE 16 (continued).

Company Unit	Philadelphia Electric Eddystone 1A	Tennessee Valley Authority Shawnee
Reason for Reheat	Equipment protection	Equipment protection
Reason for Direct	High LT required	Easiest for test system
Boiler Size (MW)	310	150
Coal		
Type	West Virginia-Pennsylvania	Kentucky-Illinois
Sulfur (percent)	2.5	1 - 3
Heating value (Btu/lb)	12,100	12,000
Scrubbing System	Mg-Ox (United Engr.)	3-10M ²
Start-up Date	7-75	4-72
Scrubbed Flue Gas		
Flow (acfm)	268,000	20,400 (3)
Temperature (°F)	127	125
SO ₂ Concentration (ppm)	50	250
Fuel and Combustion		
Combustion Chamber	External	External
Fuel Type	Oil	#2 Fuel Oil
Fuel Rate	--	-- (20)
Ductwork	Carbon steel/liner	Refractory Lining
Corrosion	--	--
Stack	--	Stess
Corrosion	--	Pitting observed
Reheat LT (°F)	125	125
Fan Position (relative to scrubber)	Upstream	Downstream
Atmospheric Effects		
Mist	--	--
Acid Rainout	--	--
Fog	--	--
Comments	Some refractory cracking has occurred due to temperature sensor malfunctions.	Internal chamber was removed due to flame instability. No corrosion problems experienced. Refractory must be heated slowly to prevent damage.
Source or Reference	P,2,12	1,2,12

--No information available

P - Personal communication

*The Shawnee Facility has 3 demonstration FGD systems, each of which can treat about 10 MW equivalent of flue gas.

Paddy's Run Unit #6--Louisville Gas and Electric: Paddy's Run Unit #6 uses natural gas in an inline combustion chamber for induced draft fan and stack protection. No problems have occurred in five years of usage. Gas is used because of its availability, while the system was selected based on the ease of retrofitting. Reheat availability has been nearly 100 percent over the operating period.

Eddystone Unit #1A--Philadelphia Electric: The Eddystone Station is on the flight path of Philadelphia International Airport. As a result, the scrubbed flue gas is reheated more than 125°F to avoid the occurrence of a visible plume. The original refractory burner lining failed due to high temperatures in startup. A new refractory and a slower heat-up period have proved satisfactory.

Shawnee--Tennessee Valley Authority: The Shawnee Plant has three small scrubbers on a larger unit. They each treat about 10 MW equivalent of flue gas. Being a small test system, direct combustion was chosen because it was the easiest way to protect downstream equipment. Fuel oil (No. 2) is fired in an external chamber and the resulting combustion products are mixed with the scrubbed flue gas. The chamber is heated at 50°F/hour during startup to prevent refractory damage. Some pitting has been observed in the FGD system stack.

Other direct combustion systems: The Delaware City Unit #1 of Delmarva Power Company will be firing syngas available from local industries at its Wellman-Lord scrubber for equipment protection and plume buoyancy. The St. Clair demonstration unit of Detroit Edison uses direct oil firing. Half of the gas from Unit #6 is scrubbed and reheated to its prescrubbed temperature. This avoids thermal shock in the stack when it is mixed with the unscrubbed gas. Bruce Mansfield Units #1 and #2 of Pennsylvania Power Company have had some flame stability problems due to flue gas infiltration into the external combustion chamber. Vibration has also caused some damage to the refractory.

Bypass Reheat--

Parameters affecting performance--Bypass reheat is the most economical form of reheat. It requires only duct work and control dampers. Additionally, both capital and operating cost savings are realized because a smaller scrubbing system can be used with this configuration. However, proposed legislation* may limit the amount of gas which can be bypassed. If 70-90 percent SO₂ removal is required for all coals (regardless of sulfur content), then the use of bypass reheat will be restricted.

Under the old NSPS of 1.2 lb SO₂/10⁶ Btu, a number of utilities contracted to burn low sulfur coal. Partial scrubbing is sufficient to meet the emission standard. The remaining gas is bypassed. Reheat and its associated benefits are obtained whether desired or not. Of the 65 wet scrubbing facilities due for startup from 1977 to 1980, 25 are planning to use bypass reheat. Only two of the installations (Allegheny Power) will be burning medium-high (2-4 percent) sulfur coal. Allegheny Power System, at its two Pleasants Station units, expects a 5-8°F temperature rise due to a 5 percent bypass. The remaining bypass installations are using low sulfur coal and bypassing 20 percent or more of the flue gas.

Bypass installations--Survey information on the Coronado Units of the Salt River Project and the R. D. Morrow unit of the South Mississippi Electric Power Association are presented below. Table 17 summarizes data for these two units. Other bypass systems are also discussed briefly.

Coronado Unit #1--Salt River Project: The Salt River Project Company was a participant in testing of the Mohave-Southern California Edison pilot scrubbers. These two pilot scrubbers used inline and indirect hot air reheat, respectively. Construction of the new scrubber for Coronado Unit #1 is based on low sulfur coal with partial flue gas bypass providing reheat. The percentage of flue gas bypassed will vary. The scrubber will

*When these questionnaires were returned by reheat users, the new SO₂ NSPS for electric utility boilers (issued on June 11, 1979) had not been promulgated.

TABLE 17. BYPASS REHEAT SYSTEMS

Company Unit	Salt River Project Coronado Unit #1	South Mississippi Electric RD Morrow Unit #1
Reason for Reheat	--	--
Reason for Bypass	Not all gas needs scrubbing to meet SO ₂ emission requirements	Not all gas needs scrubbing to meet SO ₂ emission requirements
Boiler Size (MW)	350	180
Coal		
Type	Western	--
Sulfur (percent)	1.0 (max.)	1.0
Heating Value (Btu/lb)	--	--
Scrubbing System	Limestone (Pullman-Kellogg)	Limestone (Riley-Stoker)
Start-up Date	April, 1979	August, 1978
Scrubbed Flue Gas		
Flow (acfm)	990,000	350,000
Temperature (°F)	117	126
SO ₂ Concentration (ppm)	153	--
Flue Gas Bypassed		
Percent Total Flow	220	138
Flow (acfm)	449,000	408,000
Temperature (°F)	254	290
SO ₂ Concentration (ppm)	850	--
Flue Gas to Stack		
Flow (acfm)	1,440,000	733,000
Temperature (°F)	155	187
SO ₂ Concentration (ppm)	315	--
Ductwork	Carbon steel/Precrete	Carbon steel/glass flake
Corrosion	--	--
Stack	Concrete/FRP* liner	Carbon steel/acid brick
Corrosion	--	--
Fan Position (relative to scrubber)	Upstream	--
Atmospheric Effects		
Mist	--	--
Acid Rainout	--	--
Fog	--	--
Comments	Percent bypass will maintain maximum of 0.3 lb SO ₂ /10 ⁶ Btu emission.	Scrubber treats all gas up to 62% of full load gas flow. The rest is bypassed. At 100% capacity, emissions are 1.2 lb SO ₂ /10 ⁶ Btu.
Source or Reference	P,Q,2	P,Q,2

--No information available

P - Personal communication

Q - Questionnaire response

*FRP - fiberglass reinforced plastic

treat the amount of flue gas required to keep an emission rate of 0.8 lb SO₂/10⁶ Btu, and the reheat level will vary accordingly.

R. D. Morrow Unit #1--South Mississippi Electric Power Association: Bypass reheat is used because all of the gas does not require scrubbing to meet the NSPS. The first 62 percent of the gas will be scrubbed. At higher capacities, the extra gas will be bypassed. The stack is designed for wet or dry conditions. At full load, the sulfur dioxide emission rate is 1.2 lb SO₂/10⁶ Btu.

Other bypass units: Other units burning low sulfur coal bypass about 15-40 percent of the flue gas. This gives an equivalent 25-60°F of reheat. As stated earlier, only the Allegheny Power System Pleasants units are burning medium-high sulfur coal. The utility has performed some pilot tests which indicate that 5-8°F of reheat is necessary to prevent condensation in the ducts and stack. Since startup has not occurred, this value has not been proven.

The Newton Station Unit #1 of Central Illinois Public Service will utilize bypass reheat on one module and inline reheat on the other. They are doing this to gain firsthand experience with reheat systems.

Wet Stacks--

Parameters affecting performance--As evidenced by the vendor and A/E recommendations, many do not believe reheat is necessary. They cite the extra cost of building and operating the reheat system and the operating and maintenance problems. An alternative to stack gas reheat is no reheat (operation with a wet stack). However, condensation then occurs in the ducts and stacks, mist and acid rain may occur in the near vicinity, the plume may droop with potential high ground-level pollutant concentrations, and duct and stack corrosion can occur.

Generally, corrosion following condensation is the primary adverse result of wet flue gas. The use of forced draft primary fans reduces the

negative impact of the corrosion problems. The duct walls can be insulated and lined to control condensation/corrosion. New stack linings such as fiberglass reinforced plastics, Ceilcote, Precrete, and Epoxy may limit stack corrosion. However, these linings have not been tested long enough to determine their useful life. Low flue gas velocities can be incorporated in the stack design to minimize entrainment of condensed water vapor. This should help reduce the potential for acid rain in the vicinity of the stack.

Wet stack installations--In general, wet stacks are used because of economics and the problems associated with reheat systems. The five units described in Table 18 are discussed below. Other wet stacks of interest are also discussed briefly.

Duck Creek Unit #1--Central Illinois Light Company: This utility selected a wet stack for Duck Creek based on economics. At present, it has not been run wet because all four scrubbing modules have not been completed. The utility is burning low sulfur coal without operating the scrubber until all the modules are completed. High temperatures in the stack have caused the Ceilcote to flake off in some spots. A wet stack is planned for Duck Creek Unit #2 also.

Conesville Unit #5--Columbus and South Ohio Electric Company: The wet stack was selected over reheat because of economics. Problems with the scrubber have resulted in complete bypass operation at times. The hot, bypassed gas blistered the original Ceilcote-lined stack. An acid brick stack lining has since been installed. No corrosion has been noticed over the few months it has been used with a wet gas.

Phillips--Duquesne Light Company: The Phillips and Elrama Stations were designed for wet stacks with acid brick lining. Direct combustion reheaters were included to help dissipate the plume in winter. However, these were seldom used due to operating problems and the high cost of fuel.

TABLE 18. WET STACK SYSTEMS

Company Unit	Central Illinois Light Company Duck Creek Unit #1	Calumet & South State Electric Company - Conventville Unit #3
Reason for no Reheat	Most economical	Most economical
Boiler Size (MW)	400	400
Coal		
Type	Illinois	Ohio
Sulfur - (percent)	2.5 - 4.0	4.5 - 4.9
Heating Value (Btu/lb)	10,500	10,700
Scrubbing System	Limestone (Riley-Stoker)	Lime (GDP)
Start-up Date	September, 1976	February, 1977
Scrubbed Flue Gas		
Flow (acfm)	1,200,000	1,050,000
Temperature (°F)	127	133
SO ₂ Concentration (ppm)	--	74
Ductwork	Wastalloy G	Corten/Saunders Coating
Corrosion	--	--
Stack	Carbon steel/Celcote Flakeline 15'	Concrete/acid brick
Corrosion	See comments	--
Diameter (ID-ft)	19	26
Fan Position (relative to scrubber)	Upstream	Upstream
Atmospheric Effects		
Mist	No	No
Acid Rainout	No	No
Fog	No	No
Comments	One of four modules completed in 1976. The other three were scheduled for completion in September, 1976. Therefore 75% by-pass was occurring at the time these data were gathered. Hot gas has occasionally blistered stack lining.	Originally had Celcote lined stack. Without scrubber, it was blistered lining. Acid brick lining was added and has been satisfactory.
Source or Reference	P,Q,2	P,Q,2

--No information available

P - Personal communication

Q - Questionnaire response

TABLE 18 (continued).

Company Unit	Duquesne Light Company Phillips	Pacific Power & Light Company Dave Johnston
Reason for no Reheat	Original design, reheat is used only for plume dispersion in winter.	At time of design, no reheat systems were reliable or considered necessary.
Boiler Size (MW)	410	350
Coal		Sub-bituminous
Type	--	0.5
Sulfur - (percent)	1.8 - 2.2	7,800
Heating Value (Btu/lb)	11,350	
Scrubbing System	Lime (Chemico)	Particulate removal only
Start-up Date	July, 1973	1972
Scrubbed Flue Gas		
Flow (acfm)	1,900,000	1,540,000
Temperature (°F)	120	115
SO ₂ Concentration (ppm)		--
Ductwork	Carbon steel/cerulose	--
Corrosion	--	--
Stack	Carbon steel/acid brick	Carbon steel/flake lining
Corrosion	--	Yes
Diameter (ID, ft)	16	--
Fan Position (relative to scrubber)	Between venturi and absorber	Downstream - wet
Atmospheric Effects		
Mist	No	Yes
Acid Rainout	No	No
Fog	No	No
Comments	Originally had oil-fired reheaters at Phillips and Elrama. Neither were used extensively and have both been removed. Some seepage through mortar in stack lining has occurred. Stack annulus is to be pressurized as a solution.	Have had problems in the past with the wet fan. Stack is beginning to show severe corrosion problems after 8 years of operation.
Source or Reference	P.O.1	P.O.11

--No information available

P - Personal communication

Q - Questionnaire response

TABLE 18 (continued).

Company Unit	Springfield City Utilities Southwest Unit #1
Reason for no Rereat	Rereat systems not reliable. Stack velocity and height are adequate for dispersion.
Boiler Size (MW)	200
Coal	
Type	Bituminous
Sulfur - (percent)	3.5
Heating value (Btu/lb)	11,000
Scrubbing System	Limestone (WOP)
Start-up Date	May, 1977
Scrubbed Flue Gas	
Flow (acfm)	500,000
Temperature (°F)	125
SO ₂ Concentration (ppm)	500
Ductwork	Mild steel/flake lining
Corrosion	--
Stack	Concrete/acid brick
Corrosion	No
Diameter (ID, ft)	13.9
Fan Position (relative to scrubber)	Upstream
Atmospheric Effects	
Mist	Occasionally
Acid Rainout	No
Fog	No
Comments	Stack bottom is continuously drained.
Source or Reference	P.O.2

--No information available
P - Personal communication
Q - Questionnaire response

These reheaters have since been removed. Some acidic seepage through the brick mortar in the stack has occurred, corroding the carbon steel support bands. An acid-resistant mortar was installed which stopped the seepage.

Dave Johnston--Pacific Power and Light: The Dave Johnston Plant is one of the oldest with a wet stack. In operation since 1972, the carbon steel, flake-lined stack is beginning to show severe corrosion problems. A wet fan is also used and is washed continually. It has experienced operating problems in the past including scale build-up. The scrubber is currently used for particulate removal only.

Southwest Unit #1--Springfield City Utilities (Missouri): Springfield City Utilities selected a wet stack because they felt reheat systems are not reliable. Stack configuration produces the velocity and height needed for adequate dispersion. Occasionally mist carry-over is observed when both scrubber modules are operated. No corrosion has been observed in the stack after one year of operation.

Other wet stacks: The Wellman-Lord scrubber at D. H. Mitchell Unit #11, Northern Indiana Public Service, has a natural gas reheater which has never been used. The stack is lined with fiberglass reinforced plastic (FRP). Mist carry-over has been noticed occasionally.

SURVEY SUMMARY AND CONCLUSIONS

Based on the information collected during the survey conducted for this study, the following results and conclusions were obtained:

- (1) Although the need for and use of reheat is site specific, utilities generally use reheat to protect equipment against condensation and subsequent corrosion. Plume buoyancy enhancement is often given as a secondary reason for reheat.
- (2) The degree of reheat used by industry varies from 0°F (no reheat) to more than 100°F; however, a range of about 40-60°F is typically used by operating plants.

- (3) The majority of the responding A/E's and vendors do not recommend the use of reheat systems. When reheat is requested by a customer, these companies generally recommend the indirect hot air reheat configuration because of greater reliability.
- (4) Although operating problems are greater with inline than other reheat configurations, many utility companies prefer to use inline reheat because of lower capital and operating costs.
- (5) Bypassing of unscrubbed flue gas is quite economical and is used frequently. However, future utilization may be limited by SO₂ emission standards.
- (6) Direct combustion reheat has exhibited good reliability and the best characteristics for retrofit applications. Future utilization is difficult to assess due to both economic constraints (fuel availability and price) and governmental regulations.
- (7) No problems have been encountered or identified by utilities and/or vendors with regard to reheater tube material availability.

Table 19 presents a comparison of the advantages and disadvantages of the various reheat configurations for new and retrofit installations. Much of this information is based on the responses to the OMB-approved survey. Additionally, planned and existing utilization is presented for each reheat configuration.

TABLE 19. REHEAT CONFIGURATION OPERATING CHARACTERISTICS

	Reheat Configuration					Wet Stacks
	In-line	Indirect Hot Air	Direct Combustion	Bypass	Exhaust Gas Recirculation (EGR)	
Current commercial usage (percentage of total) ^a	39	20	18	7	Not proven on commercial scale	16
Percentage of total reheat systems to be used by 1985 ^b	10	15	12	25	0	20
Advantages of configuration	(1) Simple design. (2) No increase in mass flow rate of reheat air. (3) Less costly than other systems and except bypass and direct for a set degree of reheat.	(1) No corrosion or plugging of reheat air ducts. (2) More reliable than in-line.	(1) Simple design and operation. (2) No corrosion or plugging of reheat air ducts. (3) Relatively low capital cost. (4) Easiest to retrofit.	(1) Most economical form of reheat. (2) Simple design. (3) No external energy required.	(1) Less variation than in-line. (2) Likely because low gas heated before contacting reheat air.	(1) No reheat required. (2) Significant savings exhibited compared to systems in which reheat is used.
Disadvantages of configuration	(1) Corrosion and plugging commonly occur. (2) Difficult to retrofit.	(1) Mass flow rate of reheat air increased. (2) Exhaust gases required in order to drive auxiliary air fan when needed. (3) Poor stability and incomplete combustion have been experienced in some cases when fuel oil was used. (4) Not combustion gases can damage ductwork and cause air pollution with flue gas not done properly.	(1) Cost highly variable to fuel cost. Also, low sulfur fuels (natural gas and No. 2 fuel oil) availability and/or cost may prohibit use. (2) Poor stability and incomplete combustion have been experienced in some cases when fuel oil was used.	(1) One is restricted by 50% efficiency standards. (2) May be difficult to retrofit.	(1) Not proven on commercial scale. (2) Front end experience severe corrosion problem. (3) Relatively large heat transfer area is required.	(1) Corrosion may occur (dust and stack). (2) Acid rain may occur. (3) Scrubber retrofit required to reduce acid rain and dust to stack. (4) Repairs of scrubber has blistered some acid-res stand stack linings.

^aThis percentage was developed from data which reflect present and future operation of 107 power plants. The use of wet stacks was included in the development of this percentage.

SECTION 6

THE NEED FOR STACK GAS REHEAT

Stack gas reheat (SGR) can be used to eliminate or reduce the impact of the following potential problems associated with wet stack gases from flue gas desulfurization (FGD) processes:

- (1) Corrosion of equipment downstream of the scrubber
- (2) Occurrence of acid rainout in the vicinity of the stack
- (3) Formation of a visible plume
- (4) Increased ground-level concentrations of pollutants (other than SO_2) compared to an unscrubbed flue gas due to poor plume buoyancy

In this section, the problems caused by wet stack gases are examined in detail, and the impacts of varying levels of reheat on these problems are quantified where possible. In addition, the impacts of several of the commercially available reheat systems on the problems caused by wet stack gases will be discussed. The information obtained from the user/vendor survey regarding (1) reasons for stack gas reheat, (2) degree of reheat utilized, (3) type of reheat configuration used, and (4) operating history of commercial installations are used as the bases for the information developed in this section.

A general solution to the required quantity of reheat and its impact on a wet flue gas cannot be readily determined because:

- (1) The problems associated with a wet flue gas are not interdependent; therefore, each may require a different solution.
- (2) Reheat requirements are highly site specific.
- (3) Completely eliminating the problems mentioned above requires a level of reheat that most reheat users consider impractical; therefore, a level that will reduce the potential problems but not eliminate them is normally selected.

Consequently, the occurrence of the potential problems as well as the impact of various reheat configurations and several levels of reheat on each of these problems is discussed separately. Because the use of bypass reheat is limited by air quality standards that do not restrict the use of other reheat configurations, its application is discussed separately at the end of this section.

DOWNSTREAM EQUIPMENT CORROSION

Occurrence

Because the scrubbed flue gas contains SO_2 , SO_3 , CO_2 , chlorides, and sulfuric acid mist, the flue gas can be very corrosive in the presence of moisture. Moisture can be present due to entrainment of water from the scrubber mist eliminator and/or condensation of water vapor. Since wet FGD processes saturate and cool the flue gas to its adiabatic saturation temperature, a small drop in flue gas temperature will result in water vapor condensing in the system. Such a drop in temperature can result from heat losses through the duct and stack walls. Responses to the reheat questionnaire (by FGD process vendors and A/E contractors) indicate a stack gas temperature drop of about 5°F in the stack and duct work following the scrubber.

A substantial quantity of heat can be lost through the duct work of the system. This heat loss is a function of the temperature difference between the flue gas and ambient air and the overall heat transfer coefficient of the duct wall (and insulation, if used). This overall heat transfer coefficient is made up of the following individual factors:

- (1) The heat transfer coefficient of the flue gas film on the inside of the duct
- (2) Thermal conductivity of the metal from which the duct is constructed
- (3) Thermal conductivity of the insulating material (if any is used)
- (4) The heat transfer coefficient of the air film on the outside of the duct

The heat transfer coefficient of the air film is a function of wind speed. Typically, this heat transfer coefficient is proportional to the wind speed raised to the 0.6 power ($h \propto v^{0.6}$).

When the duct work is insulated, the insulation becomes the controlling resistance to heat transfer from the flue gas to the ambient air and thereby decreases the heat loss and the flue gas temperature drop. However, it should be noted that duct work in power plants is typically insulated only in areas where employees may come in contact with hot surfaces. Calculations developed for uninsulated and insulated duct work show that insulation can reduce heat losses through the duct work by more than 90 percent (see Table 20).

Heat loss will also occur in the stack. This loss can be caused by two different mechanisms. One mechanism involves the loss of heat due to heat transfer through the stack wall. Stack insulation can be provided by building an outer stack so that the air in the annular space acts as insulation. By design, the air in the annulus becomes the controlling resistance for

TABLE 20. TEMPERATURE DROP THROUGH DUCT WITH AND WITHOUT INSULATION

	Ambient Air Temperature (°F)	Flue Gas Temperature Drop (°F) at Wind Velocity	
		0 MPH ^a	20 MPH ^a
With Insulation	0	0.03	0.03
	50	0.02	0.02
	80	0.01	0.01
Without Insulation	0	1.4	3.6
	50	0.8	2.2
	80	0.5	1.4

^aEnglish units are used throughout this report. Factors for converting these units to the international system of units are given in Appendix F.

Bases:

- (1) For the insulated duct, overall heat transfer coefficient at 0 MPH wind velocity is 0.0273 Btu/hr-ft²-°F; at 20 MPH wind velocity it is 0.0278 Btu/hr-ft²-°F (insulation thermal conductivity is 0.028 Btu/hr-ft²-°F).
- (2) For uninsulated duct, the overall heat transfer coefficient at 0 MPH wind velocity is 1.15 Btu/hr-ft²-°F; at 20 MPH it is 3.10 Btu/hr-ft²-°F.
- (3) A 500-MW unit having a flue gas flow rate of 5.14×10^6 lb/hr (at a scrubber exit temperature of 130°F) was assumed.
- (4) A rectangular (12 ft wide x 10 ft high x 100 ft long) duct having an uninsulated surface area of 12,000 ft² was assumed for all cases considered. Insulation thickness was taken as one inch.
- (5) Radiation heat transfer was assumed negligible.

heat transfer. The heat loss from a 600-foot stack and the corresponding gas temperature drop were calculated for different ambient air temperatures. For these calculations it was assumed that the inner wall thickness, annular space, and outer wall thickness decreased linearly with an increase in stack height. This allowed average overall heat transfer coefficients to be calculated for 100-foot stack height increments. These coefficients were used to develop an overall heat transfer coefficient for the stack wall. The results of these calculations are presented in Table 21.

TABLE 21. FLUE GAS TEMPERATURE DROP DUE TO HEAT LOSS FROM A 600-FOOT STACK

Ambient Air Temperature (°F)	Flue Gas Temperature Drop (°F)
0	1.5
50	1.0
80	0.6

Bases:

- (1) A 500-MW unit having a flue gas flow rate of 5.14×10^6 lb/hr (at a scrubber exit temperature of 130°F) was assumed.
- (2) Heat transfer area is 46,000 ft².
- (3) Average overall heat transfer coefficient was calculated to be 0.34 Btu/hr-ft²-°F.
- (4) Wind velocity was assumed to be 15 MPH normal to the stack axis.

As the gas rises in the stack, it undergoes isentropic expansion, which also causes a temperature drop to occur. The flue gas temperature resulting from the expansion of the gas can be estimated from the following expression:

$$T_2 = T_1 \left(\frac{P_2}{P_1} \right)^{R/C_p} \quad (1)$$

where: T_2 = exiting temperature of flue gas ($^{\circ}\text{R}$)
 T_1 = entering temperature of flue gas ($^{\circ}\text{R}$)
 P_2 = exiting pressure of flue gas (psia)
 P_1 = entering pressure of flue gas (psia)
 R = universal gas constant (Btu/lb mole- $^{\circ}\text{R}$)
 C_p = specific heat of flue gas (Btu/lb mole- $^{\circ}\text{R}$)

The use of this expression is dependent on the flue gas experiencing no (or negligible) heat loss in the stack. The small heat losses shown in Table 21 indicate that Equation 1 provides a good engineering estimate of the temperature drop due to the expansion of the gas in the stack. Using this equation, a temperature drop of about 1°F was calculated for a flue gas from a 500-MW unit that had undergone isentropic expansion in a 600-foot stack. In this calculation it was assumed that the natural draft in the stack was approximately 2 inches (H_2O) and the flue gas velocity was constant (throughout the stack). This stack draft (2 inches H_2O) is probably an upper limit of what would be expected in a utility plant environment for a saturated flue gas.

The flue gas temperature drop for the two mechanisms (heat loss through the walls of the stack and duct and temperature drop due to isentropic expansion) can probably be held to about 5°F using a double-walled stack and well-insulated ducts.

Some of the heat lost from the system may be replaced by the heat resulting from work of compression by the fan that is utilized to overcome the pressure drop incurred in the boiler-FGD unit-reheat system. The flue gas temperature resulting from adiabatic compression can be determined from the following expression:

$$t_2 = t_1 + \frac{T_1}{n} \left[\left(\frac{P_2}{P_1} \right)^{R/C_p} - 1 \right] \quad (2)$$

where: t_2 = temperature of flue gas exiting the fan ($^{\circ}\text{F}$)
 t_1 = temperature of flue gas entering the fan ($^{\circ}\text{F}$)
 T_1 = temperature of flue gas entering the fan ($^{\circ}\text{R}$)
 n = adiabatic fan efficiency
 P_2 = pressure of flue gas exiting the fan (psia)
 P_1 = pressure of flue gas entering the fan (psia)
 R = universal gas constant (Btu/lb mole- $^{\circ}\text{R}$)
 C_p = specific heat of flue gas (Btu/lb mole- $^{\circ}\text{R}$)

To determine the variation in flue gas temperature rise (across the fan) with system pressure drop, Equation 2 was solved assuming various pressure drops and fan efficiencies of 65 and 85 percent (see Figure 3). In a 500-MW power plant utilizing a limestone FGD process and an inline reheater, the total system pressure drop is approximately 40 inches of water. Of this total, about 15 inches of pressure drop is attributable to the scrubbing (9 in.) and reheat (6 in.) portion of the plant. In Figure 3, it can be seen that the flue gas temperature rise corresponding to a 40-inch pressure drop is approximately 19 $^{\circ}\text{F}$ for a flue gas at 129 $^{\circ}\text{F}$ and a fan efficiency of 85 percent. (This assumes that the fan providing the entire system pressure drop requirement is placed after the scrubber.)

Although it is apparent that the primary fan can substantially raise the flue gas temperature, the use of the work of compression to reheat flue gas is dependent on the position of the fan in the system. In a forced draft system* (see Figure 4a), the fan raises the temperature of the flue gas before it is scrubbed. It is obvious that this fan positioning will not provide any stack gas reheat as a result of the work of compression. An induced draft fan (see Figure 4b) raises the temperature of the gas

*The reader should note that the terms forced and induced draft used in this report refer to the position of the fan relative to the scrubber. In conventional power plant practice, the boiler is the reference point; a forced draft fan is upstream of the boiler while an induced draft fan follows the boiler.

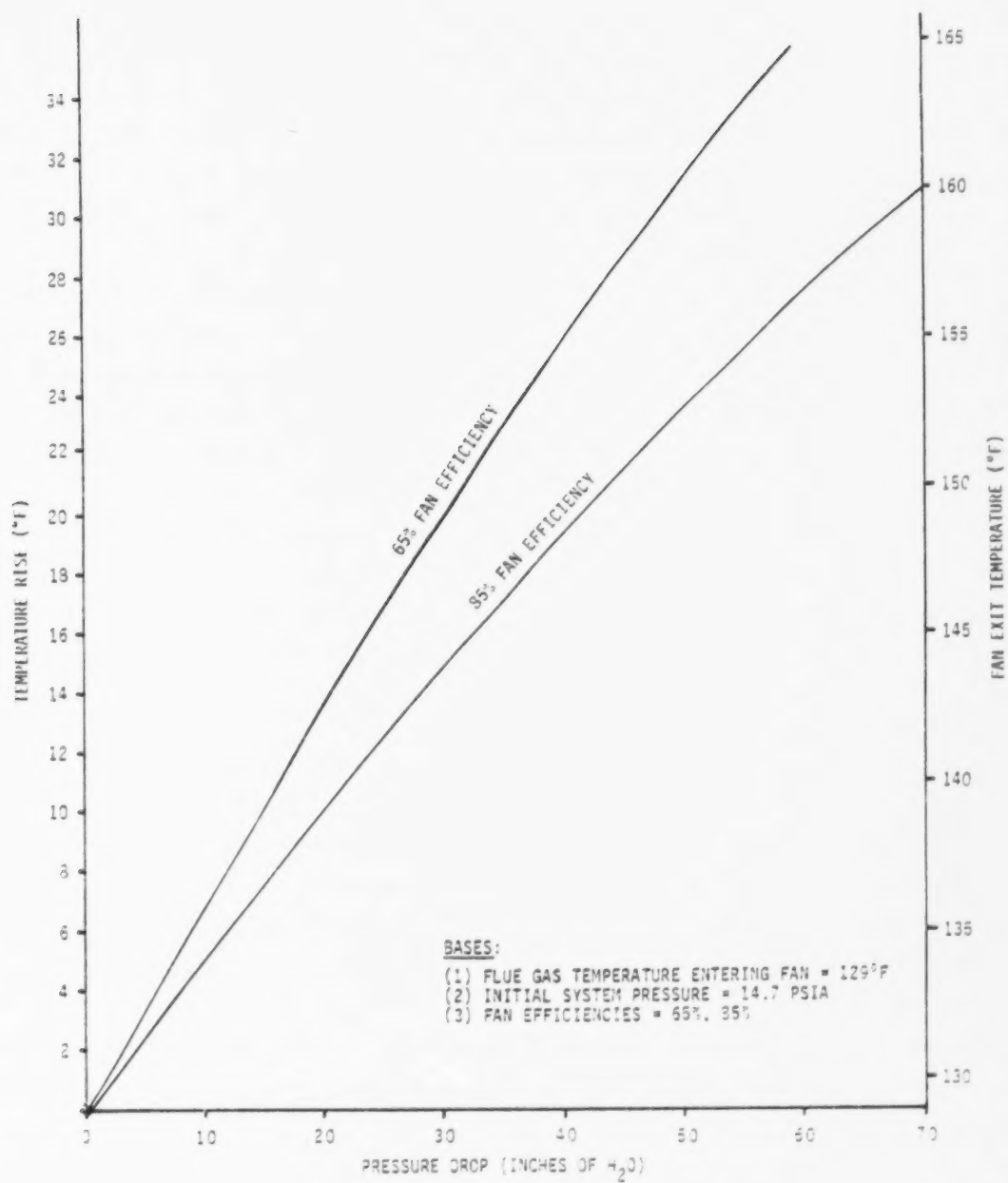
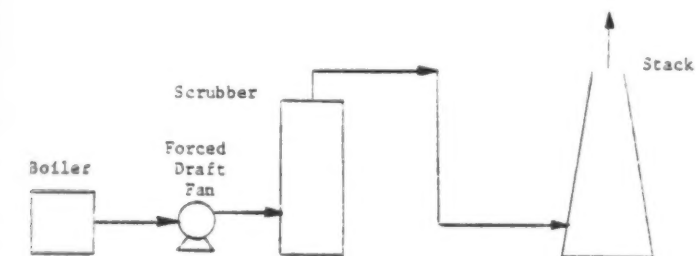
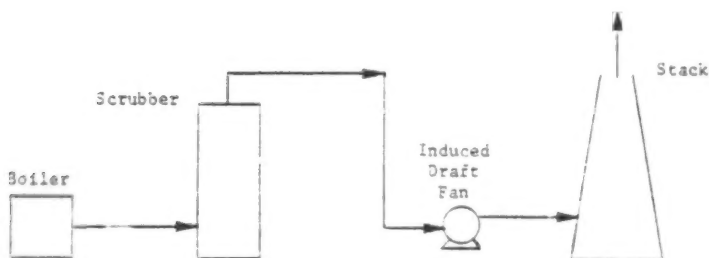


Figure 3. Calculated temperature rise due to work of compression.

after it has exited the scrubber and therefore, it may be appropriate to credit an induced draft fan with supplying a portion of the reheat desired.



(a) Forced draft fan configuration



(b) Induced draft fan configuration

Figure 4. Simplified schematic of FGD systems with forced and induced draft primary fans.*

Prevention of Condensed Water Vapor in Equipment Downstream of the Scrubber

Energy balances were developed for the inline, indirect hot air, and direct combustion reheat configurations in order to determine the quantity of heat required by each configuration to eliminate the presence of moisture downstream of the scrubber. The energy balances were developed only for these configurations because of their distinct impact on the wet flue gas.

*The reader should note that the terms forced and induced draft used in this report refer to the position of the fan relative to the scrubber. In conventional power plant practice, the boiler is the reference point; a forced draft fan is upstream of the boiler while an induced draft fan follows the boiler.

Inline Reheat Energy Balance--

The heat input supplied by an inline reheat configuration is dependent on variables such as the quantity of mist entrained in the flue gas, the heat lost from the stack and duct, heat input due to the work of compression from the induced draft fan, the change in potential and kinetic energies of the flue gas and entrained mist, and the scrubber exit and stack exit temperatures. For the system shown in Figure 5a, a steady-state energy balance permits calculation of the quantity of energy that an inline reheater must supply in order to provide a given level of reheat $(T_s - T_{fs})$.

$$Q_R = m_f C_{p,f} (T_s - T_{fs}) + m_w (h_{w,s} - h_{w,fs}) + \frac{g}{j g_c} (\Delta z) (m_f + m_w) \quad (3)$$
$$+ \frac{m_f}{2 g_c j} (v_s^2 - v_{f,fs}^2) + \frac{m_w}{2 g_c j} (v_s^2 - v_{w,fs}^2) - Q_f + Q_{ti}$$

where Q_R = heat supplied by reheater (Btu/hr)
 m_f = flue gas flow rate (lb/hr)
 $C_{p,f}$ = mean specific heat of flue gas (Btu/lb-°F)
 T_s = temperature of flue gas at the stack outlet (°F)
 T_{fs} = flue gas temperature at the exit of the scrubber (°F)
 m_w = mass flow rate of liquid carry-over (lb/hr)
 $h_{w,s}$ = enthalpy of vaporized entrained mist at the stack outlet (Btu/lb)
 $h_{w,fs}$ = enthalpy of the entrained mist at the scrubber outlet (Btu/lb)
 g = local acceleration of gravity (ft/sec²)
 g_c = conversion factor, (ft-lb_m/sec²-lb_f)
 j = mechanical equivalent of heat (778 ft-lb_f/Btu)
 Δz = net elevation traversed by flue gas (approximately the difference in duct and stack outlet height)(ft)
 v_s = velocity of the gas at the stack outlet (ft/sec)
 $v_{f,fs}$ = velocity of the flue gas at the scrubber outlet (ft/sec)

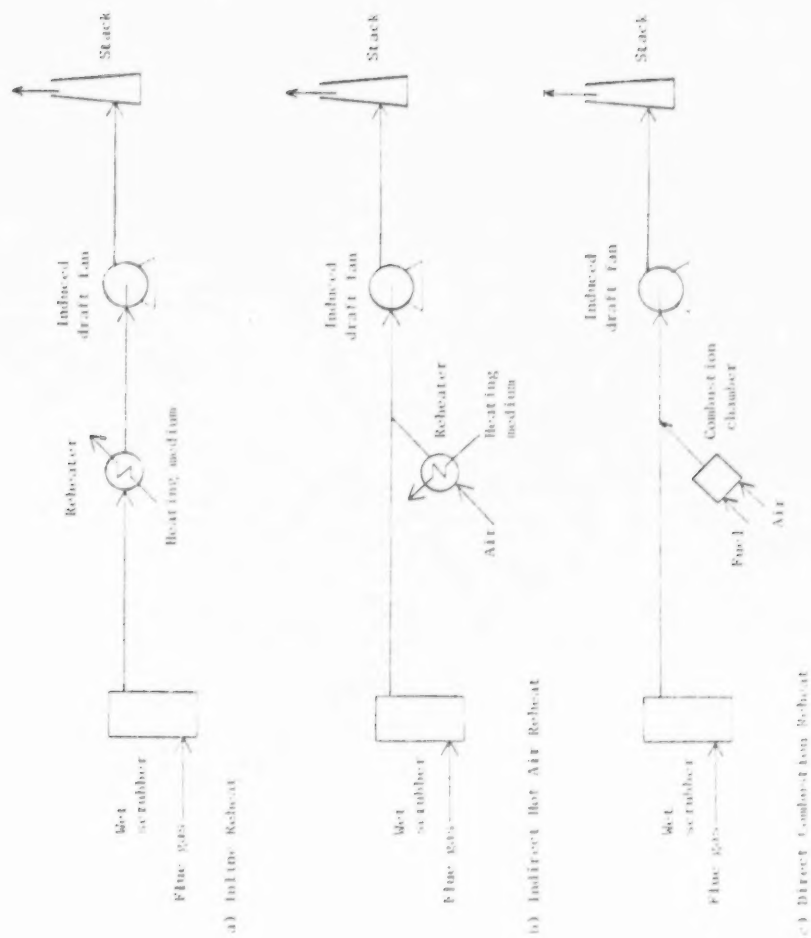


Figure 5. Induced draft fan arrangement of inline, indirect, and direct combustion reheat configurations.

$v_{w,fs}$ = velocity of the entrained mist at the scrubber outlet (ft/sec)

Q_f = heat resulting from the work of compression by the induced draft fan (Btu/hr) (This term is zero if there is no fan between the scrubber and the stack.)

Q_{t1} = total heat lost from the duct and stack (Btu/hr)

A rigorous examination of the inline reheat configuration requires the solution to Equation 3. However, in this study certain assumptions are made to simplify the calculational procedure. These include (1) assuming that the potential* and kinetic terms in Equation 3 are small and (2) assuming that only the latent heat of vaporization must be input to the mist carried over from the mist eliminator (i.e., the change in sensible heat of the vaporized mist is negligible). Making these assumptions allows Equation 3 to be reduced to the following expression:

$$Q_R = m_f C_{p,f} (T_s - T_{fs}) + m_w \lambda_w + Q_{t1} - Q_f \quad (4)$$

where, in addition to previously defined symbols:

λ_w = latent heat of vaporization of water at the scrubber exit temperature (Btu/lb)

When the prevention of water vapor condensation is the specific objective, Equation 4 can be solved for the minimum reheat energy (Q_{RM}) required to prevent water vapor condensation. This minimum occurs when the flue gas stack exit temperature (T_s) equals its dew point (T_d). Therefore, Equation 4 becomes:

$$Q_{RM} = m_f C_{p,f} (T_d - T_{fs}) + m_w \lambda_w + Q_{t1} - Q_f \quad (5)$$

It should be noted that typically T_d will be slightly higher than T_{fs} because some mist carry-over from the scrubber will evaporate.

*For tall stacks this term begins to be significant. For example, a 300 ft stack requires about 1.5°F of reheat to provide the increased potential energy of each pound of gas exiting the stack. This is about 3% of the energy required for 50°F of reheat.

Indirect Hot Air Reheat Energy Balance--

A generalized steady-state energy balance for the induced draft primary fan arrangement of an indirect hot air reheat system (Figure 5b) follows:

$$\begin{aligned} Q_R = & m_f C_{p,f} (T_s - T_{fs}) + m_w (h_{w,s} - h_{w,fs}) + m_a C_{p,a} (T_s - T_a) \\ & + \frac{g}{j g_c} (\Delta z) (m_f + m_w + m_a) + \frac{m_f}{2 g_c j} (v_s^2 - v_{f,fs}^2) + \frac{m_w}{2 g_c j} (v_s^2 - v_{w,fs}^2) \\ & + \frac{m_a}{2 g_c j} (v_s^2) - Q_f + Q_{t1} \end{aligned} \quad (6)$$

where, in addition to the previously defined symbols:

$$\begin{aligned} m_a &= \text{mass flow rate of air (lb/hr)} \\ C_{p,a} &= \text{heat capacity of air (Btu/lb-°F)} \\ T_a &= \text{ambient air temperature (°F)} \\ T_s &= \text{temperature of flue gas-air mixture at top of stack (°F)} \end{aligned}$$

As in the case of the inline reheat system, assuming that the kinetic and potential energy terms are small and that the change in sensible heat of the vaporized mist is negligible, Equation 6 reduces to:

$$Q_R = m_f C_{p,f} (T_s - T_{fs}) + m_w \lambda_w + m_a C_{p,a} (T_s - T_a) - Q_f + Q_{t1} \quad (7)$$

The heat supplied by the reheater is also defined by the following equation:

$$Q_R = m_a C_{p,a} (T_h - T_a) \quad (8)$$

where T_h = temperature of heated air (°F)

Equations 7 and 8 define an indirect hot air reheat system for a given level of reheat ($T_s - T_{fs}$). To determine the minimum reheat energy required (Q_{RM}) to prevent water vapor condensation in downstream equipment, the dew

point (T_d) of the flue gas-air mixture (exiting the stack) is substituted for T_s (temperature of the flue gas-air mixture at the stack outlet) in Equations 7 and 8. Therefore, these two equations become:

$$Q_{RM} = m_f C_{p,f} (T_d - T_{fs}) + m_w \lambda_w + m_a C_{p,a} (T_d - T_a) - Q_f + Q_{tl} \quad (9)$$

$$Q_{RM} = m_a C_{p,a} (T_h - T_a) \quad (10)$$

There are many solutions to these equations since for any non-trivial mass flow rate of air (m_a) there is a heated air temperature (T_h) which will provide the reheat level. It should be noted that dilution of the wet flue gas with heated air will, in most cases, cause the dew point of the flue gas-air mixture to drop below the flue gas saturation temperature (at the scrubber exit).

Direct Combustion Reheat Energy Balance--

Like indirect hot air reheat, direct combustion reheat also dilutes the flue gas; however, the dilution effect is not as pronounced as that exhibited by indirect hot air reheat. Making the same assumptions* as before, the simplified steady-state energy balance equations for a direct combustion reheat system (Figure 5c) are:

$$Q_R = fq \quad (11)$$

and

$$Q_R = m_f C_{p,f} (T_s - T_{fs}) + m_w \lambda_w + m_g C_{p,g} (T_s - T_g) + Q_{tl} - Q_f \quad (12)$$

where, in addition to the previously defined symbols:

f = flow rate of combustion fuel (lb/hr)
 q = heating value (LHV) of fuel (Btu/lb)

*Kinetic and potential energy terms are small. Sensible heat of vaporized mist is negligible.

m_g = mass flow of combustion gases (lb/hr)
 T_g = temperature of combustion gases ($^{\circ}$ F)

These equations can be used to solve for the minimum reheat fuel requirement that will prevent the occurrence of moisture in the equipment downstream of the scrubber. This minimum will occur when the stack exit temperature is equal to the dew point of the flue gas-reheat combustion gas mixture.

Results--

The respective energy balances were used to calculate the minimum energy requirements of the inline, indirect hot air, and direct combustion reheat configurations to vaporize any liquid carry-over from the scrubber and prevent water vapor condensation downstream of the scrubber. Because the actual heat required is dependent on several factors such as heat losses and the presence of entrained liquid, the reheat needed will be very site specific. In all the cases considered, the primary fan was assumed to be a forced draft fan (with respect to the scrubber) so that any heat due to the work of compression was added to the flue gas prior to its being scrubbed; therefore, the Q_f portion of the developed expressions was considered to be zero. For all the configurations analyzed, it was assumed that heat losses from the system (from stack and duct work) would result in a 5° F drop in the flue gas temperature from the reheater to the stack exit. The results of these calculations are presented in Table 22. These data show that the

- (1) Inline reheat configuration requires the lowest heat input to prevent condensation downstream of the scrubber, and
- (2) Indirect hot air configuration requires the highest heat input to prevent condensation.

As the data in the table indicate, all the reheat configurations studied change the dew point due to the vaporization of entrained liquid or dilution with air or combustion gases or both.

TABLE 22. HEAT INPUT REQUIRED TO PREVENT THE OCCURRENCE OF MOISTURE
DOWNSTREAM OF THE SCRUBBER.

	Reheat Configuration					
	Inline			Direct Combustion		
Entrained Liquid (gr/scf) ¹ (lb/hr)	0.012 130	0.805 8840	0.012 130	0.805 8840	0.012 130	0.805 8840
Dew Point Temperature at Stack Exit (°F)	129	129.5	129	129.5	128.4	128
Ambient Air Characteristics						
Temperature (°F)	-	-	60	60	60	60
Relative Humidity (%)	-	-	50	50	50	50
Heated Air Temperature (°F)	-	-	-	-	400	400
Flow Rate (lb/hr)	-	-	-	-	92,500	212,500
Assumed Heat Loss (10 ⁶ Btu/hr) ²	6.6	6.6	6.6	6.6	6.6	6.6
Heat Required For Vaporizing Entrainment (10 ⁶ Btu/hr)	0.13	9.0	0.13	9.0	0.13	9.0
Sensible Heat Required for Reheat Medium ³ (10 ⁶ Btu/hr)	-	-	0.01	0.02	1.6	3.6
Theoretical Heat Required to Prevent Presence of Moisture (10 ⁶ Btu/hr)	6.7	15.6	6.7	15.6	8.3	19.2
Presence of Moisture (Z of boiler input)	0.15	0.35	0.15	0.35	0.18	0.43

¹Reference 3 reports entrainment loading of .012 gr/scf for a bottom wash mist eliminator and .805 gr/scf for a top wash mist eliminator.

²Total heat losses assumed to be equivalent for all configurations and correspond to a 5°F drop in flue gas temperature.

³This sensible heat equals the heat required to raise the reheat medium from its ambient temperature to the stack exit temperature.

Bases:

- (1) 500 MW unit
- (2) 9,000 Btu/kWh heat rate
- (3) Forced draft fan configuration (with respect to the scrubber)
- (4) Flue gas saturation temperature = 129°F
- (5) Flue gas flow rate = 5.14 x 10⁶ lb/hr
- (6) Flue gas heat capacity = 0.26 Btu/lb-°F
- (7) For direct combustion, natural gas ambient temperature assumed to be 60°F.
- (8) Potential and kinetic energy changes considered negligible.

It is apparent from Table 22 that the level of reheat required to prevent condensation in the system is highly dependent on the quantity of liquid entrainment in the flue gas. Although a study of mist eliminator performance was beyond the scope of this study, the results illustrate the importance of good mist eliminator design and operation.

Overall, it is concluded that stack gas reheat is a viable technique to eliminate the presence of moisture downstream of the mist eliminator and, therefore, to protect the system from subsequent corrosion. While the quantity of heat required to prevent the presence of moisture is influenced by several factors, this study showed the required heat is highly dependent on the quantity of moisture entrained in the flue gas. It is stressed that only the minimum quantity of reheat required to prevent the presence of moisture in the system was considered in this study. In this analysis, the total heat input required to vaporize the liquid carried over from the mist eliminator and to offset heat losses from the system was determined. However, analyses of other factors such as the impact of liquid droplet size, composition, and residence time (in the ductwork) on heat input requirements were not considered. It is expected that the reheat requirements in an actual plant (to prevent the occurrence of moisture) will be higher than the minimum levels calculated in this study. However, the actual requirements can only be determined by a thorough evaluation of an operating plant situation.

VISIBLE PLUME FORMATION

Occurrence

A saturated flue gas can result in the formation of a visible plume. While a visible plume does not have a negative impact on the environment, it is aesthetically displeasing and potentially hazardous to ground and air traffic. The mechanics of visible plume formation are illustrated in Figure 6. Ambient air conditions (temperature, relative humidity) are represented

by point 1 in this figure. Point 2 corresponds to the conditions of the hot flue gas as it exits the boiler. The flue gas is saturated and cooled during the scrubbing operation and is ultimately represented by point 3. As the saturated flue gas exits the stack, it mixes with ambient air. This mixing process is represented by line 3-1. A plume is formed when the ambient air-saturated flue gas mixture intersects the saturation curve and crosses into the fogged field area of the chart.^{20,21}

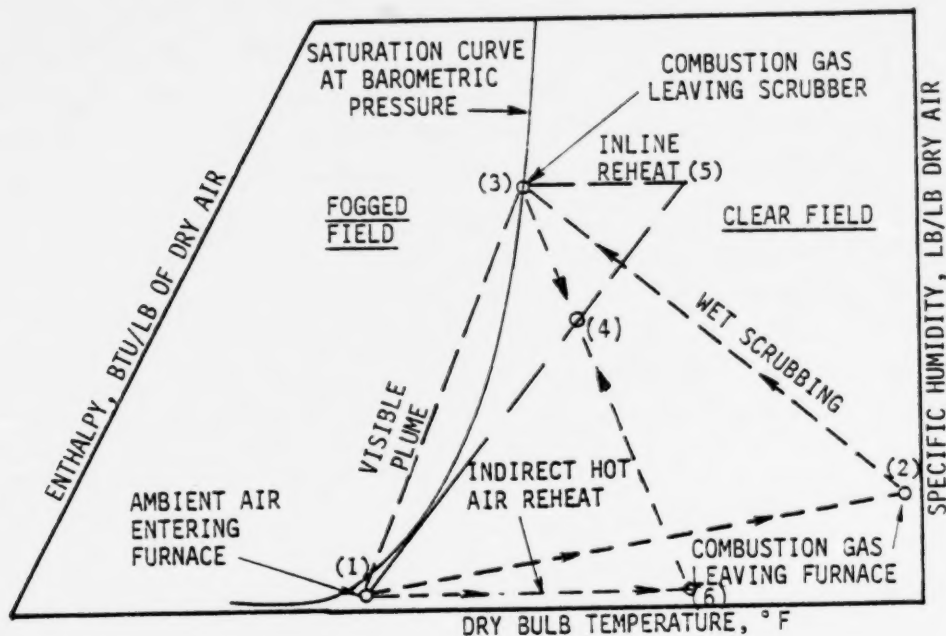


Figure 6. Psychrometric chart showing state point of flue gas-air mixture during combustion, scrubbing, and reheat.²⁰

Prevention

Prevention of a visible plume with the use of reheat involves the clockwise rotation of line 3-1 (saturated flue gas-ambient air mixing line) until it is tangent to the saturation curve. The temperature to which the flue gas must be heated to prevent the formation of a visible plume is represented by point 5 when inline reheat is used and point 4 when indirect hot air reheat is used. Point 6 represents the heated air temperature prior to mixing with the flue gas in the indirect hot air reheat method.

The heat inputs required by the inline and indirect hot air configurations to prevent the formation of a visible plume at various climatic conditions were calculated. Only these two configurations were considered with regard to the prevention of a visible plume because the impacts of the inline and indirect configurations are expected to define the range of impacts of reheat on the formation of a visible plume. The bases for and the results of these calculations are presented in Table 23. The results show that:

- (1) The greatest quantity of reheat to prevent visible plume formation is required when the ambient air is at low temperature and high humidity. For example, at 100 percent relative humidity and an ambient air temperature of 32°F, an inline reheater would have to raise the flue gas temperature to approximately 440°F in order to avoid a visible plume.
- (2) As expected, the theoretical heat required to suppress a visible plume is approximately the same for the inline and indirect hot air reheat configurations for the same climatic conditions.

Impact of Reheat on Visible Plume Formation and Characteristics

Radian's Wet Plume Model was used to analyze the effect of reheat on the length of a visible plume and the plume's detached distance (the distance from the stack before the plume becomes visible). The length of the plume is the actual length as measured down the center of the plume. A description of

TABLE 23. REHEAT REQUIRED TO PREVENT A VISIBLE PLUME

Reheat Configuration	Inline			Indirect Hot Air		
	60	60	32	60	60	32
Ambient Air Temperature (°F)	50	100	100	50	100	100
Relative Humidity (%)	129	129	129	129	129	129
Flue Gas (at scrubber exit)						
Saturation Temperature (°F)	-	-	-	400	400	400
Heated Air Temperature (°F)	-	-	-	0.84	1.75	4.52
Quantity of Heated Air Required (10 ⁶ lb/hr)	183	240	439	166	196	253
Stack Gas Reheat Temperature Required To Prevent Visible Plume (°F)	71.0	149.0	416.0	71.0	149.0	416.0
Reheat Required to Prevent Visible Plume Formation (10 ⁶ Btu/hr)				(70.5)	(147.7)	(412.0)
(% Boiler Input)	1.58	3.31	9.24	1.58	3.31	9.24
				(1.56)	(3.28)	(9.15)

Bases and Comments:

- (1) Flue gas flow rate (exiting scrubber) is 5.14×10^6 lb/hr (representative of a 500-MW plant).
- (2) Flue gas water content (exiting scrubber) is assumed to be 14.7 percent (vol.) for all cases.
- (3) A heat rate of 9000 Btu/kWh was assumed.
- (4) Heat losses in duct work and stack are assumed to be negligible.
- (5) Liquid entrainment from the mist eliminator is assumed to be zero.
- (6) Forced draft primary fan arrangement (with respect to the scrubber).
- (7) Reheat requirements in parentheses for indirect hot air were developed by taking credit for heat due to work of compression produced by the auxiliary fan. The pressure drop in the air heater was assumed to be 6 in. H₂O and an 85 percent fan efficiency was also assumed.

the model is presented in Appendix A. In this analysis, 648 cases were developed. This reflected 162 different combinations of meteorological conditions and four scrubbing-reheat levels. The meteorological and stack exit parameters used in this model are shown in Table 24.

An initial conclusion of the study was that changes in ambient temperature with respect to height (atmospheric stability) had little effect on plume length or the detached distance of the plume. Consequently, only a neutrally stratified atmosphere was considered for further analysis, and only these data are presented below.

Presented in Tables 25 through 27 are data developed using the model for the length of a visible plume and the detached distance that result from unscrubbed flue gas and scrubbed flue gases that were reheated by 0°F, 50°F, and 100°F. These data show that:

- (1) An unscrubbed flue gas will form a visible plume at 100 percent relative humidity regardless of the ambient air temperature (in the 0-100°F range). This occurs since the stack gas contains more water vapor than the saturated ambient air. Therefore, as the stack gas is cooled, this additional water vapor in the plume will condense (according to the wet plume model).

As the relative humidity drops, the temperatures at which an unscrubbed flue gas will form a visible plume are decreased. A psychrometric chart (Figure 7) is used to illustrate this model result. This figure shows that at 50 percent relative humidity the unscrubbed flue gas will form a visible plume at ambient air temperatures less than about 25°F. However, at 0 percent relative humidity the same flue gas would form a visible plume at ambient temperatures less than about 19°F.

- (2) At nearly all ambient air conditions, a scrubbed flue gas with no reheat forms a visible plume immediately as the gas exits the stack. Also, the plume length of a scrubbed gas is substantially longer than the plume formed by an unscrubbed flue gas at comparable ambient air conditions.

TABLE 24. PARAMETERS FOR UTILIZATION IN WET PLUME MODEL (500 MW PLANT)

Scrubbing-Reheat Levels	STACK PARAMETERS				
	Stack Exit Temperature (°F)	Stack Exit Velocity (ft/sec)	H ₂ O Mole ^a Fraction	Stack Radius (ft)	Stack Height (ft)
Unscrubbed	300	35.0	0.088	15.3	300
Scrubbed, No Reheat	129	28.7	0.147	15.3	300
Scrubbed, 50°F Reheat ^b	179	31.1	0.147	15.3	300
Scrubbed, 100°F Reheat ^b	229	33.5	0.147	15.3	300

METEOROLOGICAL PARAMETERS			
Wind Speed (mph)	Surface Air Temperatures (°F)	Vertical Temp. Gradients (°F/10 ³ ft)	Relative Humidities (%)
5, 15, 25	0, 20, 40, 60, 80, 100	-5.4 (neutral)	0, 50, 100
			Surface Atmospheric Pressure (psia)
			14.7

^a Assumed stack exit water vapor content for all cases investigated.^b Using an inline reheater.

TABLE 25. VISIBLE PLUME LENGTH AND DETACHED DISTANCE
(NEUTRAL STRATIFICATION, WIND SPEED = 5 MPH)

Relative Humidity (%)	Ambient Air Temp (°F)	Scrubbing - Reheat Level					
		Unscrubbed			Scrubbed Plus 50°F Reheat		
		Detached Distance (feet)	Plume Length (feet)	Detached Distance (feet)	Detached Distance (feet)	Plume Length (feet)	Detached Distance (feet)
0	0	75	400	0	731	16	712
	20	-	-	0	380	20	351
	40	-	-	0	200	33	148
	60	-	-	0	98	-	-
	80	-	-	0	30	-	-
	100	-	-	-	-	-	-
50	0	72	964	0	728	16	692
	20	151	151	0	364	20	305
	40	-	-	0	184	-	-
	60	-	-	0	72	-	-
	80	-	-	-	-	-	-
	100	-	-	-	-	-	-
100	0	72	964	0	728	16	692
	20	118	118	0	364	20	305
	40	377	377	0	184	-	-
	60	754	754	0	72	-	-
	80	863	863	0	-	-	-
	100	866	866	0	-	-	-

- Indicates the plume was never visible.

++ Indicates the plume was visible for a distance beyond the 1640 foot (500 meters) limit in the model.

TABLE 26. VISIBLE PLUME LENGTH AND DETACHED DISTANCE
(NEUTRAL STRATIFICATION, WIND SPEED = 15 MPH)

Relative Humidity (%)	Ambient Air Temp (°F)	Scrubbing - Reheat Level					
		Unscrubbed			Scrubbed Plus 50°F Reheat		
		Detached Distance (feet)	Plume Length (feet)	Detached Distance (feet)	Detached Distance (feet)	Plume Length (feet)	Detached Distance (feet)
0	0	79	512	0	974	16	935
	20	-	-	0	485	20	446
	40	-	-	0	246	33	184
	60	-	-	0	112	-	-
	80	-	-	0	30	-	-
	100	-	-	-	-	-	-
50	0	75	197	0	++	16	++
	20	174	184	0	961	20	899
	40	-	-	0	469	30	394
	60	-	-	0	226	-	-
	80	-	-	0	82	-	-
	100	-	-	-	-	-	-
100	0	75	++	0	++	16	++
	20	131	++	0	++	20	++
	40	518	++	0	++	30	++
	60	1230	++	0	++	52	++
	80	1473	++	0	++	272	++
	100	1512	++	0	++	813	++

- Indicates the plume was never visible.

++ Indicates the plume was visible for a distance beyond the 1640 foot (500 meter) limit in the model.

TABLE 27. VISIBLE PLUME LENGTH AND DETACHED DISTANCE
(NEUTRAL STRATIFICATION, WIND SPEED = 25 MPH)

Scrubbing - Reheat Level									
Relative Humidity (%)	Ambient Air Temp (°F)	Unscrubbed		Scrubbed		Scrubbed Plus 50°F Reheat		Scrubbed Plus 100°F Reheat	
		Detached Distance (meters)	Plume Length (meters)	Detached Distance (meters)	Plume Length (meters)	Detached Distance (meters)	Plume Length (meters)	Detached Distance (meters)	Plume Length (meters)
0	0	89	659	0	1273	16	1214	33	1161
	20	-	-	0	620	20	574	46	515
	40	-	-	0	305	32	230	-	-
	60	-	-	0	131	-	-	-	-
	80	-	-	0	33	-	-	-	-
	100	-	-	-	-	-	-	-	-
50	0	85	1496	0	++	16	++	33	++
	20	207	226	0	++	20	1151	46	1059
	40	-	-	0	++	33	505	89	354
	60	-	-	0	++	-	-	-	-
	80	-	-	0	++	-	-	-	-
	100	-	-	-	-	-	-	-	-
100	0	82	++	0	++	16	++	33	++
	20	154	++	0	++	20	++	46	++
	40	718	++	0	++	30	++	75	++
	60	-*	**	0	++	62	++	230	++
	80	-*	**	0	++	374	++	1263	++
	100	-*	**	0	++	1263	++	-*	-*

- Indicates the plume was never visible

++ Indicates the plume was visible for a distance beyond 1640 foot (300 meter) limit in the model.
 * In this case, a plume would have occurred; however, it would have occurred at a distance greater than the limits in the model. Therefore, the detached distance could not be projected.
 ** Plume cannot be estimated because the plume was formed at a detached distance that is greater than the limits of the plume.

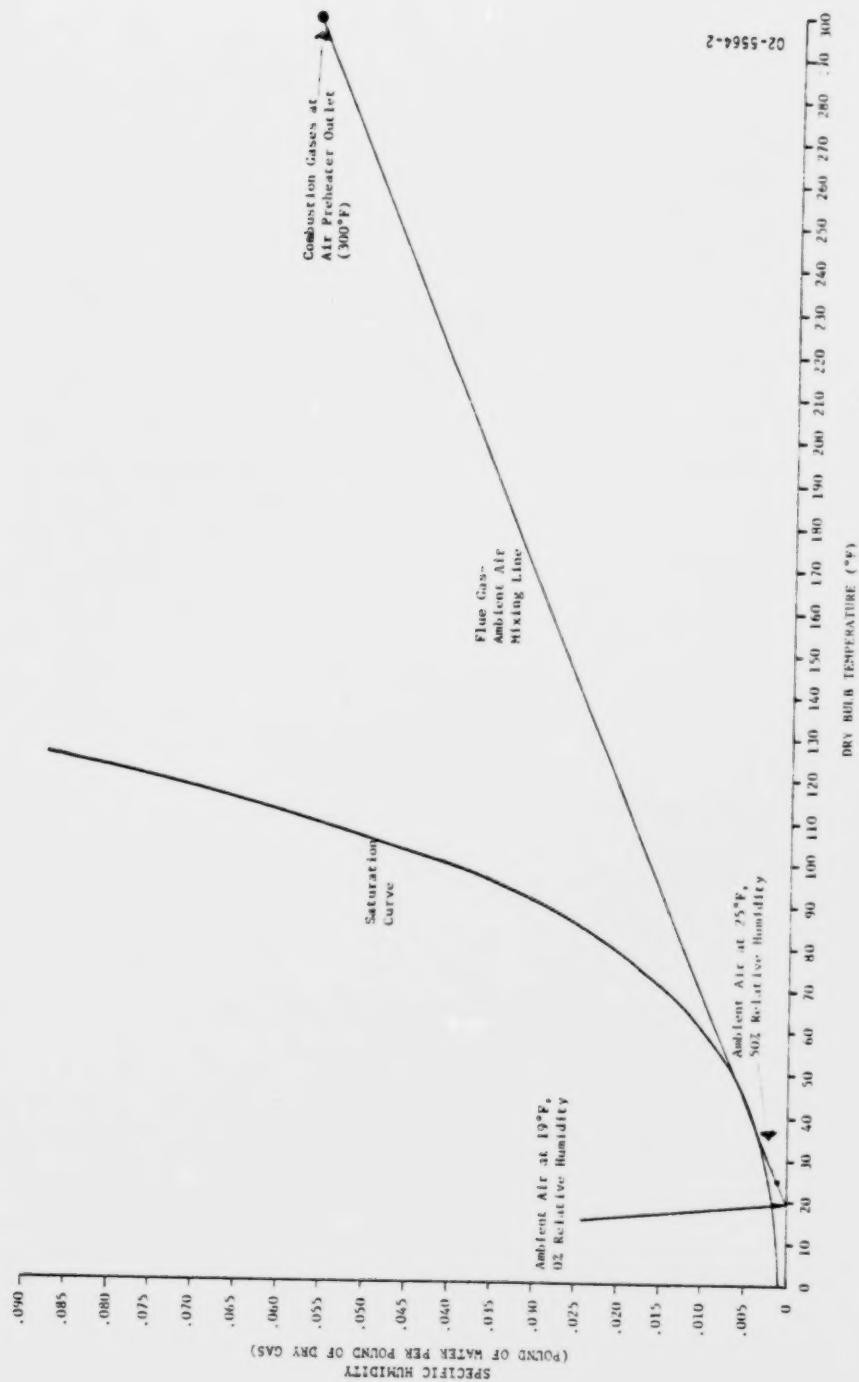


Figure 7. Psychrometric chart showing the influence of relative humidities on the temperature range at which an unscrubbed flue gas will form a visible plume.

- (3) At the low (0 percent) and moderate (50 percent) humidities analyzed in this study and ambient air temperatures above 40°F, reheating a scrubbed flue gas by 50°F to 100°F significantly increases the detached distance and reduces the length of the plume that results from scrubbing. However, at 100 percent relative humidity, the impact of these levels of reheat is diminished. As before, a psychrometric chart is used to illustrate this conclusion (see Figure 8). This figure shows that the plume length associated with 50 percent relative humidity (line EF) should be shorter than that resulting at 100 percent (line DB).
- (4) The length of the visible plume is increased as the wind speed increases.

The model-predicted plume length data in Table 25 are presented graphically in Figure 9. This figure shows the effect of reheat on plume length for relative humidities of 0 and 50 percent and different ambient air temperatures at a constant wind speed of 5 mph. This figure also emphasizes the increased length of a visible plume that results from scrubbing. It is also apparent from Figure 9 that even substantial levels of reheat (~100°F) may only slightly reduce the length of a visible plume caused by scrubbing at low or moderate ambient air temperatures.

Figure 10 shows the effect of scrubbing and reheat on the detached distance of a plume for different wind velocities and a constant relative humidity of 100 percent. This figure shows that the detached distance of the visible plume resulting from a scrubbed flue gas is shorter than that from an unscrubbed flue gas for each ambient air temperature considered. In fact, a scrubbed stack gas will form a visible plume as soon as it exits the stack at most climatic conditions. It is also apparent in Figure 10 that reheating the scrubbed flue gas by 50-100°F does not increase the detached distance to its initial length (that length which corresponds to an unscrubbed plume). However, reheating a scrubbed stack gas by 50°F may provide a detached distance of at least 10-15 feet for those conditions under which a visible plume is formed.

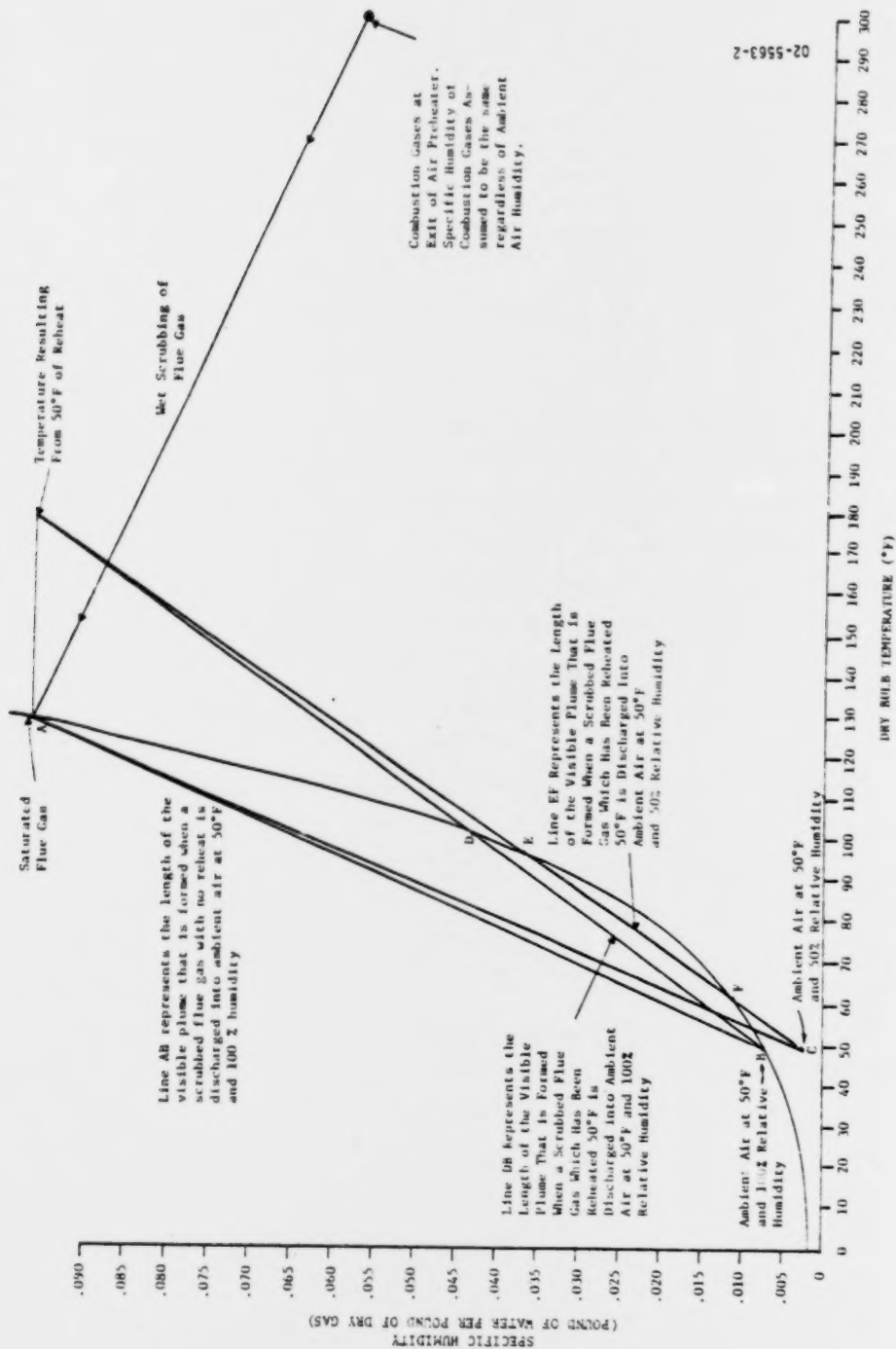
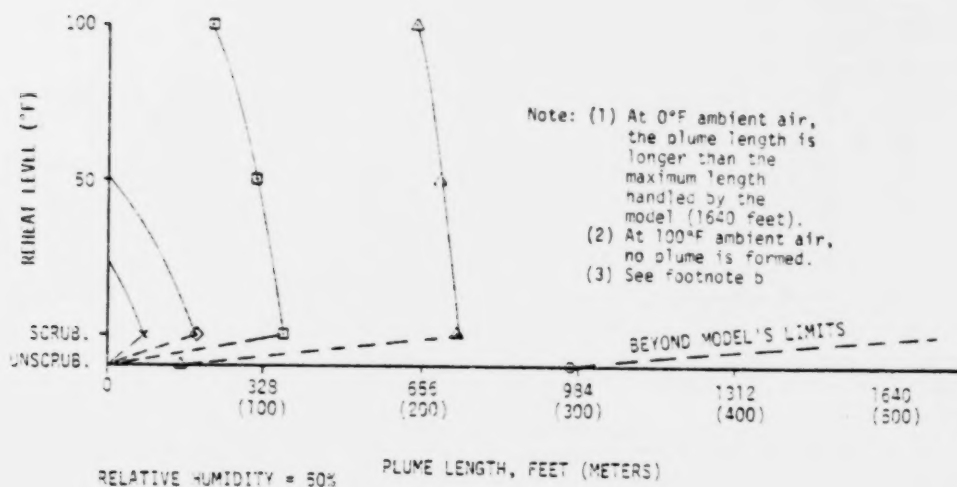
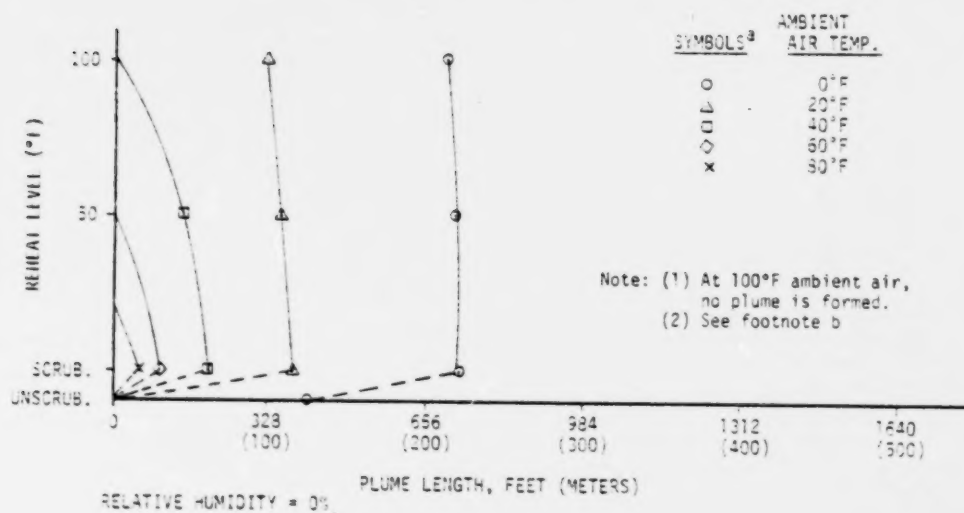


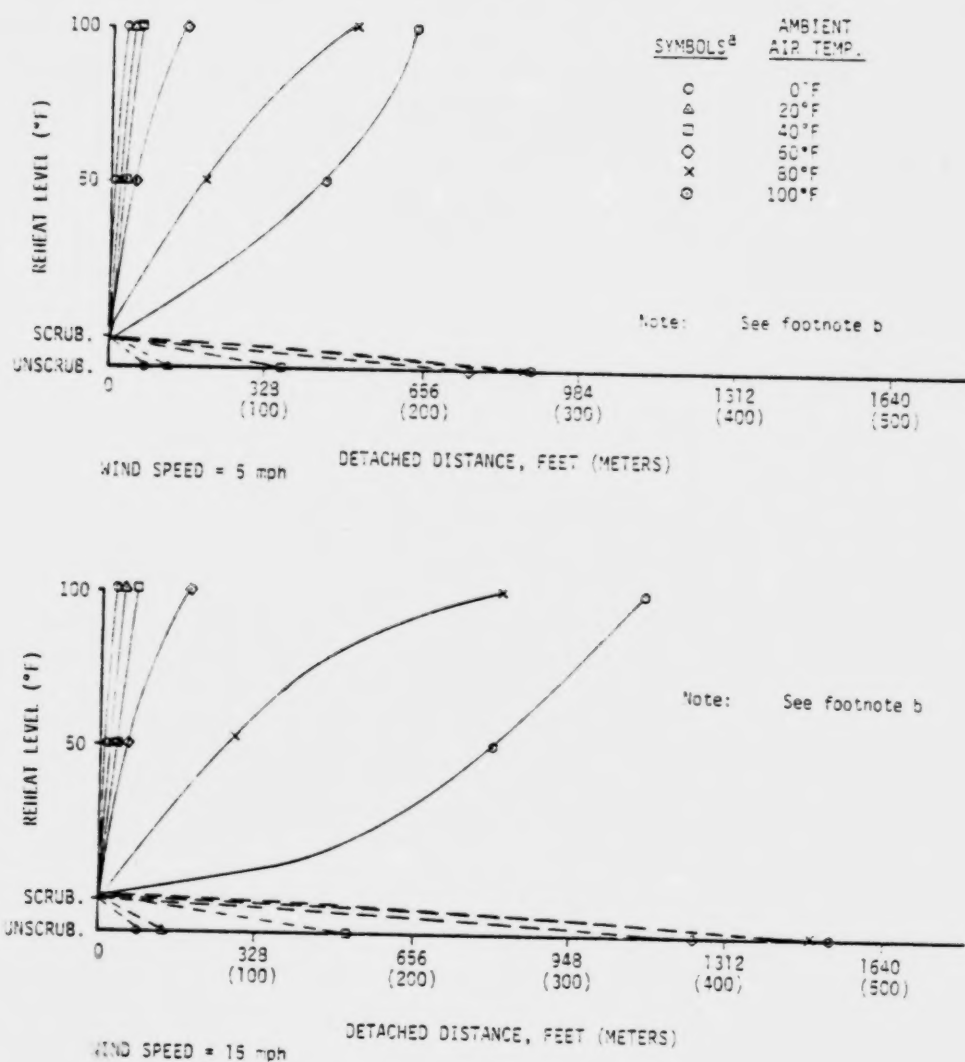
Figure 8. Psychrometric chart showing the impact of 50°F reheat on visible plume length at different relative humidities.



^aThe symbols do not represent data points, but rather are model solutions for specific stack gas parameters.

^bThe dashed lines shown in this figure do not indicate a physical connection between the unscrubbed and scrubbed flue gases; these lines facilitate the comparison of the detached distances of plumes resulting from these gases.

Figure 9. Impact of scrubbing and reheating on visible plume length at various ambient air temperatures and relative humidities (neutral stratification, wind speed = 5 mph).



^aThese symbols do not represent data points, but rather are model solutions for specific stack gas parameters.

^bThe dashed lines shown in this figure do not indicate a physical connection between the unscrubbed and scrubbed flue gases; these lines facilitate the comparison of the plume lengths resulting from these gases.

Figure 10. Predicted impact of wind speed and reheat on detached distance of visible plume (neutral stratification, relative humidity = 100 percent).

In summary, the following results were obtained using the Wet Plume Model:

- (1) Scrubbing leads to an increased plume length and a decreased detached distance of the plume from the stack.
- (2) There are some climatic conditions, such as low temperature and high humidity, at which the increased plume length and decreased detached distance that result from scrubbing cannot be significantly reversed with the levels of reheat (0 to 100°F increase in flue gas temperature) currently used by industry.
- (3) Reheat can significantly decrease plume length and increase detached distance at conditions of mild temperature and low humidity; however, at these conditions a short plume is likely to occur, whether reheat is used or not.

ACID RAINOUT IN THE VICINITY OF THE STACK

Occurrence

Acid (H_2SO_4 and H_2SO_3) rainout* in the vicinity of the stack can be generated by two mechanisms in a boiler-FGD system. One mechanism involves the formation of SO_3 which then reacts with H_2O vapor in the system to form H_2SO_4 vapor. Because the dew point of sulfuric acid is higher than the adiabatic saturation temperature of the flue gas, the H_2SO_4 vapor is condensed to a mist, which then may agglomerate into rain droplets as the flue gas exits the stack.

The second mechanism involves the presence of moisture on the stack wall due to the condensation of water vapor and/or liquid carry-over from the mist eliminator and subsequent absorption and oxidation of residual SO_2 . The resulting sulfurous and sulfuric acid droplets are entrained in the gas stream. When the velocity of the gas is no longer sufficient to entrain the

*Other acids present include nitrous, nitric, hydrochloric, carbonic, and hydrofluoric.

droplets, rain may result from the plume. The degree of rainout has been correlated to the presence of condensation in the stack and the stack gas velocity. Rainout potential is greatest when there is substantial condensate present in the stack and the gas velocity is greater than 25 ft/sec.²² Stacks are usually designed for velocities greater than 25 ft/sec.

Prevention

Reheat can be used to suppress acid rainout by:

- (1) Preventing condensation of water vapor from occurring in the duct and stack downstream of the scrubber due to heat losses from stack or duct work
- (2) Vaporizing any entrained liquid from the mist eliminator
- (3) Vaporizing any sulfuric acid mist that is present in the system

The heat required to prevent the presence of moisture downstream of the scrubber is substantially less than the heat which is required to vaporize sulfuric acid mist. Preventing the condensation of water vapor requires the input of enough heat to keep the scrubbed flue gas above its dew point, which is approximately 125 to 140°F. Vaporizing any sulfuric acid that is present requires the flue gas to be heated to a temperature higher than the sulfuric acid dew point, which is approximately 200 to 300°F. Even though all the sulfuric acid in the system can be vaporized with a substantial heat input, sulfuric acid condensation may occur when the flue gas exits the stack and mixes with the cooler ambient air.

Predicted Impact of Reheat on Rainout From Plume

Although little work has been done on rainout from power plant stacks, considerable work has been done on rainout from cooling towers, and several theories have been suggested to explain its occurrence. Two of the most

prominent theories were presented by Blum²³ and Overcamp and Hoult²⁴ (also Martin and Barber²⁵). Blum concluded that rainout would occur when the liquid density in the plume was $3.12\text{--}6.24 \times 10^{-5} \text{ lb/ft}^3$ ($0.5\text{--}1.0 \text{ gm/m}^3$). Overcamp and Hoult concluded that rainout was caused by entrained mist. As their basis, these investigators estimated that at a condition of 0.5 percent water vapor supersaturation in the plume, about 100 seconds were required before a droplet could grow (by the mechanism of water vapor condensation) to the size that would rain from the plume.

In this study, a Wet Plume Simulation Model (described in Appendix A) was used to simulate the water content of a flue gas plume for different meteorological conditions and degrees of reheat. Based on the two theories presented above, the model was used to study the effect of reheat on the density of condensed water vapor in the plume and the time length over which the water density was equal to or greater than a specified density. The data generated by the model for different wind speeds are presented in Tables 28 through 30. The data in Table 28 on (1) the time length the density of condensed water vapor in a visible plume is equal to or greater than 3.12 and $6.24 \times 10^{-5} \text{ lb/ft}^3$ (0.5 and 1.0 gm/m^3) and (2) the maximum density attained by the condensed water vapor in a visible plume are graphically presented in Figures 11 and 12. The data in Tables 28 through 30 and these figures show that:

- (1) As the relative humidity increases, the maximum water density and the time length that the density of condensed water vapor in the plume is equal to or greater than 3.12 and $6.24 \times 10^{-5} \text{ lb/ft}^3$ (0.5 and 1 gm/m^3) is increased for the unscrubbed and scrubbed (with and without reheat) stack gases.
- (2) Scrubbing with no reheat significantly increases (compared to an unscrubbed plume);
 - the temperature range in which condensed water vapor is present in the plume,
 - the time length that the density of the condensed water vapor is above any given limit, and
 - the maximum condensed water vapor density.

TABLE 28. PLUME CHARACTERISTICS FOR VARIOUS SCRUBBING AND REHEAT LEVELS (NEUTRAL ATMOSPHERE, WIND SPEED = 5 MPH)

SCRUBBING AND REHEAT LEVELS													
Relative Humidity (%)	Ambient Air Temperature (°F)	Unscrubbed			Scrubbed, No Reheat			Scrubbed, 50°F Reheat			Scrubbed, 100°F Reheat		
		Time $\rho > 0.5 \text{ gm/m}^3$ (sec)	Time $\rho > 1 \text{ gm/m}^3$ (sec)	Maximum Density (gm/m ³)	Time $\rho > 0.5 \text{ gm/m}^3$ (sec)	Time $\rho > 1 \text{ gm/m}^3$ (sec)	Maximum Density (gm/m ³)	Time $\rho > 0.5 \text{ gm/m}^3$ (sec)	Time $\rho > 1 \text{ gm/m}^3$ (sec)	Maximum Density (gm/m ³)	Time $\rho > 0.5 \text{ gm/m}^3$ (sec)	Time $\rho > 1 \text{ gm/m}^3$ (sec)	Maximum Density (gm/m ³)
0	0	12	7	2	28	21	25	26	19	17	24	17	10
	20	-	-	-	18	15	24	16	13	11	14	11	6
	40	-	-	-	10	9	18	8	6	4	-	-	-
	60	-	-	-	5	5	10	-	-	-	-	-	-
	80	-	-	-	1	1	2	-	-	-	-	-	-
	100	-	-	-	-	-	-	-	-	-	-	-	-
50	0	18	10	2	40	26	> 25	36	24	17	32	21	11
	20	0	0	< 0.25	29	21	25	26	22	12	22	16	6
	40	-	-	-	18	15	19	15	12	6	9	5	2
	60	-	-	-	10	9	12	-	-	-	-	-	-
	80	-	-	-	4	3	5	-	-	-	-	-	-
	100	-	-	-	-	-	-	-	-	-	-	-	-
100	0	27	13	3	60	33	30	53	30	17	47	26	11
	20	17	0	1	70	35	25	60	30	12	51	26	7
	40	0	0	1	227+	37	19	88	30	7	59	22	3
	60	100+	0	1	227+	43	13	225+	25	3	50+	0	1
	80	135+	90+	2	228+	228+	7	19.3+	136+	2	165+	116+	2
	100	147+	129+	3	229+	229+	4	177+	157+	4	163+	144+	3

Note: $0.5 \text{ gm/m}^3 = 3.12 \times 10^{-3} \text{ lb/ft}^3$; $1.0 \text{ gm/m}^3 = 6.24 \times 10^{-3} \text{ lb/ft}^3$.

- Indicates plume was not visible; consequently, no condensed water was present in the plume.

+ This is only an approximate time because the plume surpassed the 1640 foot (500 meter) validity limit of the model.

TABLE 29. PLUME CHARACTERISTICS FOR VARIOUS SCRUBBING AND REHEAT LEVELS (NEUTRAL ATMOSPHERE, WIND SPEED = 15 MPH)

SCRUBBING AND REHEAT LEVELS														
Relative Ambient Air Humidity Temperature (°F)	(2)	Unscrubbed			Scrubbed, No Reheat			Scrubbed, 50°F Reheat			Scrubbed, 100°F Reheat			Maximum Density (gm/m ³)
		Time (sec)	Time (sec)	Maximum Density (gm/m ³)	Time (sec)	Time (sec)	Maximum Density (gm/m ³)	Time (sec)	Time (sec)	Maximum Density (gm/m ³)	Time (sec)	Time (sec)	Maximum Density (gm/m ³)	
0	0	11	8	2	25	19	25	23	17	17	21	16	11	11
20	20	-	-	-	16	13	25	14	12	11	12	11	6	6
40	40	-	-	-	9	8	18	7	6	4	-	-	-	-
60	60	-	-	-	5	5	10	-	-	-	-	-	-	-
80	80	-	-	-	1	1	2	-	-	-	-	-	-	-
100	100	-	-	-	-	-	-	-	-	-	-	-	-	-
50	0	16	9	2	35	28	>25	32	21	17	29	19	11	11
20	20	0	0	<0.25	25	19	25	22	17	12	20	17	6	6
40	40	-	-	-	16	13	18	13	10	6	8	5	2	2
60	60	-	-	-	9	8	12	-	-	-	-	-	-	-
80	80	-	-	-	4	3	5	-	-	-	-	-	-	-
100	100	-	-	-	-	-	-	-	-	-	-	-	-	-
100	0	24	12	3	52	29	31	46	26	17	41	23	1	1
20	20	15	0	1	58	30	25	50	27	12	43	23	7	7
40	40	0	0	1	76	32	19	58	26	7	44	19	3	3
60	60	0	0	1	78+	34	13	75+	20	3	12	0	1	1
80	80	0	0	1	78+	37	8	38+	0	1	6+	0	1	1
100	100	0	0	1	79+	79+	3	23+	0	1	10+	0	1	1

Note: $0.5 \text{ gm/m}^3 = 3.12 \times 10^{-5} \text{ lb/ft}^3$; $1.0 \text{ gm/m}^3 = 6.24 \times 10^{-5} \text{ lb/ft}^3$.

- Indicates plume was not visible; consequently, no condensed water was present in the plume.

+ This is only an approximate time because the plume surpassed the 1640 foot (500 meter) validity limit of the model.

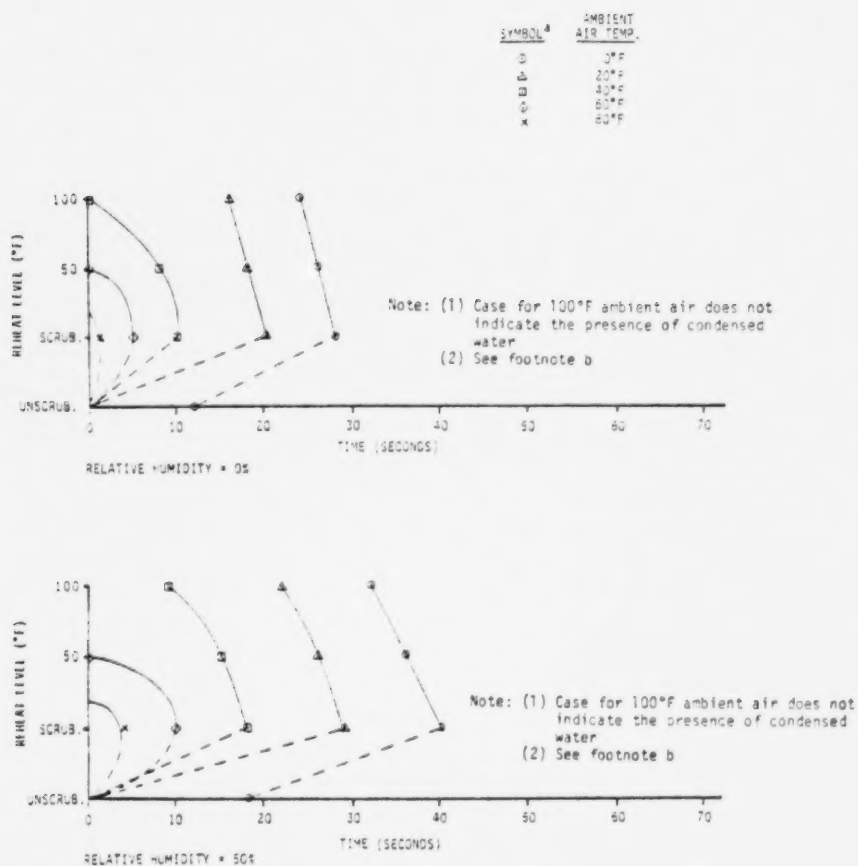
TABLE 30. PLUME CHARACTERISTICS FOR VARIOUS SCRUBBING AND REHEAT LEVELS (NEUTRAL ATMOSPHERE, WIND SPEED = 25 MPH)

SCRUBBING AND REHEAT LEVELS																
Relative Humidity (%)	Ambient Air Temperature (°F)	Unscrubbed			Scrubbed, No Reheat			Scrubbed, 50°F Reheat			Scrubbed, 100°F Reheat					
		Time $\rho > 0.5 \text{ gm/m}^3$ (sec)	Time $\rho > 1 \text{ gm/m}^3$ (sec)	Maximum Density (gm/m^3)	Time $\rho > 0.5 \text{ gm/m}^3$ (sec)	Time $\rho > 1 \text{ gm/m}^3$ (sec)	Maximum Density (gm/m^3)	Time $\rho > 0.5 \text{ gm/m}^3$ (sec)	Time $\rho > 1 \text{ gm/m}^3$ (sec)	Maximum Density (gm/m^3)	Time $\rho > 0.5 \text{ gm/m}^3$ (sec)	Time $\rho > 1 \text{ gm/m}^3$ (sec)	Maximum Density (gm/m^3)			
0	0	9	6	2	22	17	25	21	18	16	19	14	11			
	20	-	-	-	14	12	25	13	11	11	11	9	5			
	40	-	-	-	8	8	18	6	5	4	-	-	-			
	60	-	-	-	4	4	10	-	-	-	-	-	-			
	80	-	-	-	1	1	2	-	-	-	-	-	-			
50	0	14	8	2	31	21	>25	28	19	17	26	17	11			
	20	0	0	<0.25	22	17	25	20	15	12	17	13	6			
	40	-	-	-	14	12	18	11	9	6	7	5	2			
	60	-	-	-	8	7	12	-	-	-	-	-	-			
	80	-	-	-	3	3	5	-	-	-	-	-	-			
100	0	-	-	-	-	-	-	-	-	-	-	-	-			
	20	21	11	3	46	26	31	41	23	17	37	21	11			
	40	0	0	1	47+	27	25	44	24	12	38	20	7			
	60	-	-	1	47+	20	19	46+	23	7	36	17	3			
	80	-	-	-	48+	28	13	45+	17	3	1+	0	1			
100	80	-	-	-	46	28	8	30+	0	1	0	0	1			
	100	-	-	-	49+	23	3	2+	0	1	-	-	-			

Note: $0.5 \text{ gm/m}^3 = 3.12 \times 10^{-5} \text{ lb/ft}^3$; $1.0 \text{ gm/m}^3 = 6.24 \times 10^{-5} \text{ lb/ft}^3$.

- Indicates plume was not visible; consequently, no condensed water was present in the plume.

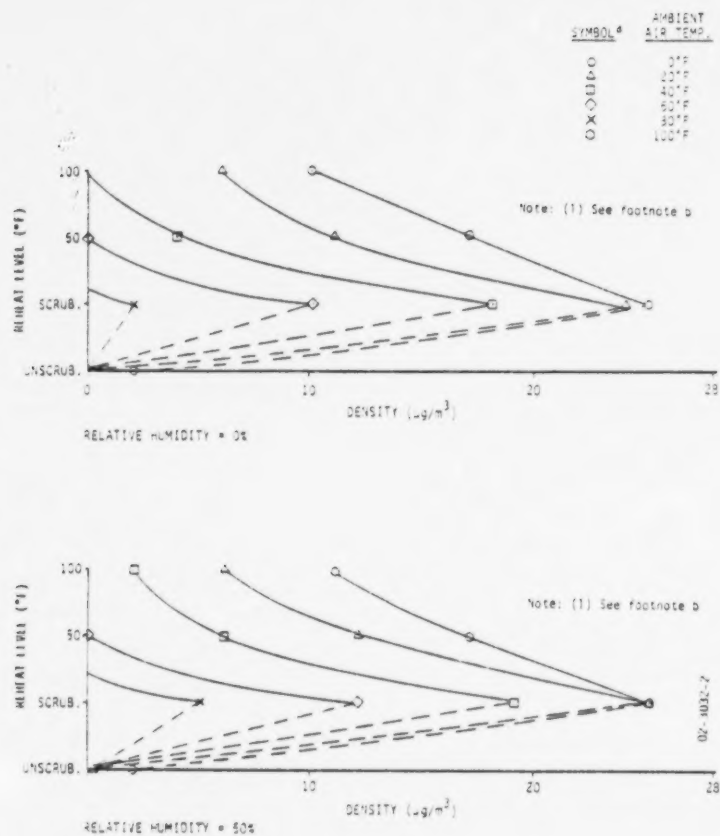
+ This is only an approximate time because the plume surpassed the 1640 foot (500 meters) validity limit of the model.



^aThese symbols do not represent data points, but rather are model solutions for specific stack gas parameters.

^bThe dashed lines shown in this figure do not indicate a physical connection between the unscrubbed and scrubbed flue gases; these lines facilitate the comparison of the properties exhibited by the condensed water vapor in the visible plumes resulting from these gases.

Figure 11. Model-predicted time lengths that the density of the condensed water vapor in visible plumes was greater than 3.12×10^{-5} lb/ft³ for various reheat levels (neutral atmosphere, wind speed = 5 mph).



^aThese symbols do not represent data points, but rather are model solutions for specific stack gas parameters.

^bThe dashed lines shown in this figure do not indicate a physical connection between the unscrubbed and scrubbed flue gases; these lines facilitate the comparison of the properties exhibited by the condensed water vapor in the visible plumes resulting from these gases.

Figure 12. Model-predicted maximum densities attained by condensed water vapor in visible plumes for various reheat levels (neutral atmosphere, wind speed = 5 mph).

- (3) At low and moderate humidities (represented by 0 and 50 percent in this study), reheating a scrubbed flue gas by 50°F does not significantly reduce either the time the density of condensed water vapor is greater than 3.12×10^{-5} lb/ft³ (0.5 gm/m³) or the maximum density attained by condensed water vapor in the visible plume unless the ambient air temperature is 60°F or higher.
- (4) The impact of reheat is diminished as the relative humidity increases. Figure 11 clearly illustrates that at 40°F and zero percent humidity, 100°F of reheat reduces the time the density of the condensed water vapor is equal to or greater than 3.12×10^{-5} lb/ft³ to zero seconds; however, at 50 percent humidity, 100°F of reheat reduces this time to approximately 9 seconds.
- (5) An increase in wind speed has essentially no effect on the maximum density of condensed water in the plume and slightly shortens the time the condensed water is equivalent to or greater than the specified density limit.

It should be noted that the trends outlined by data corresponding to the 100 percent relative humidity and 60°F to 100°F ambient air temperature cases are not as well defined as in other cases. These anomalies are a result of the model's validity limits being exceeded by such a high humidity case. However, these anomalies should not invalidate the trends and conclusions developed from the overall data presented in Tables 28 through 30.

Analysis of the concentration of condensed water in a stack plume shows that reheat may have a significant impact on rainout at conditions of mild temperatures and low relative humidities; however, this conclusion is very speculative since the mechanism causing rainout is not fully understood. Analysis of the effect of reheat on rainout at a commercial installation should be undertaken to better define the potential benefit of reheat in reducing the impacts of this problem.

INCREASED GROUND-LEVEL POLLUTANT CONCENTRATIONS

Occurrence

The ground-level concentration of pollutants resulting from dispersion of stack gases is dependent on plume buoyancy, which is affected by the temperature of the flue gas. As the plume rises, it is in vigorous turbulent motion. This turbulence is caused by momentum and buoyancy forces. The momentum forces are effective only for a short distance downwind from the stack. The buoyancy forces then become the dominant forces and accelerate the plume upward because the flue gas is hotter and, therefore, less dense than the air.* These forces will continue to drive the flue gas upward as long as it is hotter than the ambient air. Buoyancy-induced turbulence can be effective for a distance that is on the order of several hundred stack diameters downwind from the stack.

Unscrubbed stack gases are emitted to the atmosphere at about 300°F. Scrubbed stack gases (without reheat) are emitted to the atmosphere at about 125-140°F. Therefore, the plume rise associated with a scrubbed plume is considerably less than with an unscrubbed plume. Ground-level concentrations of pollutants not removed by the scrubbing process (for example, NO_x) will generally be higher for plants with wet SO_2 scrubbing than those without scrubbing. Stack gas reheat can be used to enhance plume buoyancy for scrubbed stack gases and therefore reduce ground-level concentrations of SO_2 and NO_x .

Impact of Reheat on Ground-Level Pollutant Concentration

With the use of the plume modeling program described in Appendix A, the effect of reheat on the short term (three-hour) SO_2 and NO_x ground-level

*This assumes that the densities of air and the stack gas are equal at the same temperatures and pressures. This is a close approximation for air and stack gases.

concentrations was analyzed. Of three possible atmospheric stabilities, only two, unstable and neutral, were studied because these stabilities produce high ground-level pollutant concentrations. With these stabilities, the model was used to predict the impact of reheat on maximum ground-level pollutant concentrations. The occurrence of an unstable atmosphere is relatively infrequent and is caused by intense, solar heating of the ground. This results in large vertical temperature gradients. The heated air rises and undergoes vigorous mixing. When the plume is caught up in this mixing, it is brought to the ground relatively close to the stack. At this distance the plume has not been greatly diluted. A neutral atmosphere occurs more frequently than an unstable atmosphere and produces lower ground-level pollutant concentrations compared to the unstable atmosphere.

The meteorological conditions used with the unstable atmosphere were a 5-mph wind speed, an ambient air temperature of 60°F, and an ambient temperature gradient of -10.7 °F/1000 ft. The flue gas, stack, and emission parameters used in the model are given in Table 31. The results of this analysis are illustrated in Figures 13 and 14 and show that:

- (1) The highest SO₂ ground-level concentrations are exhibited by unscrubbed flue gas. However, since scrubbing does not remove NO_x, the unscrubbed flue gas exhibits the lowest ground-level NO_x concentrations compared to all of the scrubbing-reheat levels analyzed.
- (2) Scrubbing the flue gas reduces the maximum ground-level SO₂ concentration by approximately 48 percent. However, scrubbing increases the ground-level NO_x concentration by approximately 160 percent over that of the unscrubbed flue gas. Both the SO₂ and NO_x concentrations that result from scrubbing are below applicable ambient air quality standards.
- (3) Reheating the scrubbed flue gas by 50°F reduces the ground-level SO₂ and NO_x concentrations approximately 33 percent compared to scrubbing with no reheat.
- (4) The addition of 100°F of reheat to the scrubbed flue gas reduces the ground-level SO₂ and NO_x concentrations by about 47 percent compared to a flue gas which has been scrubbed but not reheated.

TABLE 31. FLUE GAS, STACK AND EMISSION PARAMETERS

	Flue Gas Exit Temperature (°F)	Flue Gas Exit Velocity (ft/sec)	Stack Radius (ft)	Stack Height (ft)	Emission Rates (lb/hr) ^a	
					Short-Term SO ₂	Annual SO ₂
Unscrubbed	300	35.0	15.3	300	25,130	20,104
Scrubbed, No Reheat	129	28.7	15.3	300	5,025	4,020
Scrubbed, 50°F Reheat	179	31.1	15.3	300	5,025	4,020
Scrubbed, 100°F Reheat	229	33.5	15.3	300	5,025	4,020

^a Annual rates are based on 80% utilization of power plant.

Bases:

(1) SO₂ removal (in the scrubber) is assumed to be 80%.

(2) Flue gas composition (representative of 500-MW Power Plant):

Component	Scrubber Inlet		Scrubber Exit	
	(lbs/hr)	(wt %)	(lbs/hr)	(wt %)
N ₂	3,450,000	70.3	3,450,000	67.7
O ₂	258,200	5.3	258,200	5.1
CO ₂	904,200	18.4	904,200	17.8
SO ₂	25,130	0.5	5,025	0.1
SO ₃	317	0.0	317	0.0
HCl	3,022	0.1	3,022	0.1
H ₂ O	661	0.1	0	0.0
	264,500	5.4	472,200	9.3

Note: quantity of CO is very small and is consequently included with CO₂.

(3) Coal composition:

Component	Wt % (as fired)
C	57.56
H ₂	4.14
N ₂	1.29
O	7.00
S	3.12
Cl	0.15
Ash	16.00
H ₂ O	10.74

Higher Heating Value - 10,500 Btu/lb

(4) Meteorological conditions:

	Instable Atmosphere	Neutral Atmosphere
Ambient Air Temperature (°F)	60	60
Wind Speed (mph)	5	18
Temperature Gradient (°F/10 ³ ft)	-10.7	-5.4

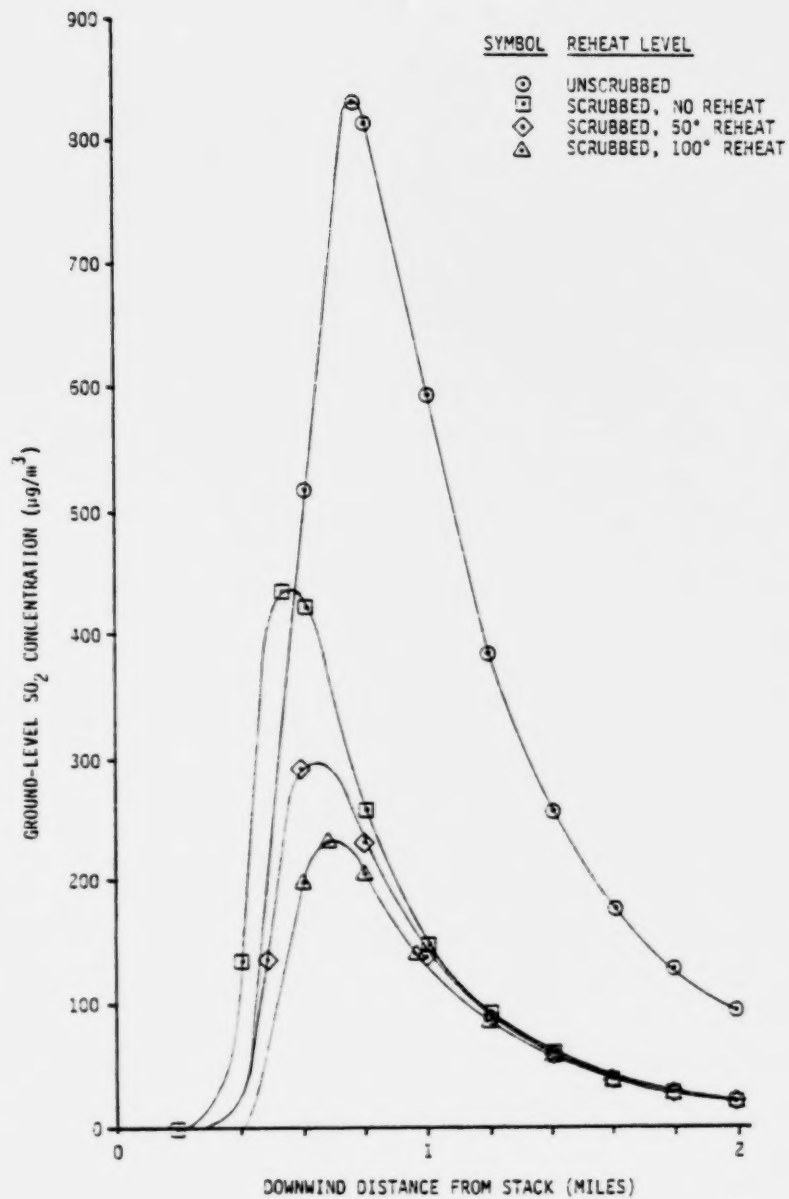


Figure 13. Model-predicted three-hour, ground-level SO₂ concentration downwind of the stack for an unstable atmosphere (wind speed = 5 mph).

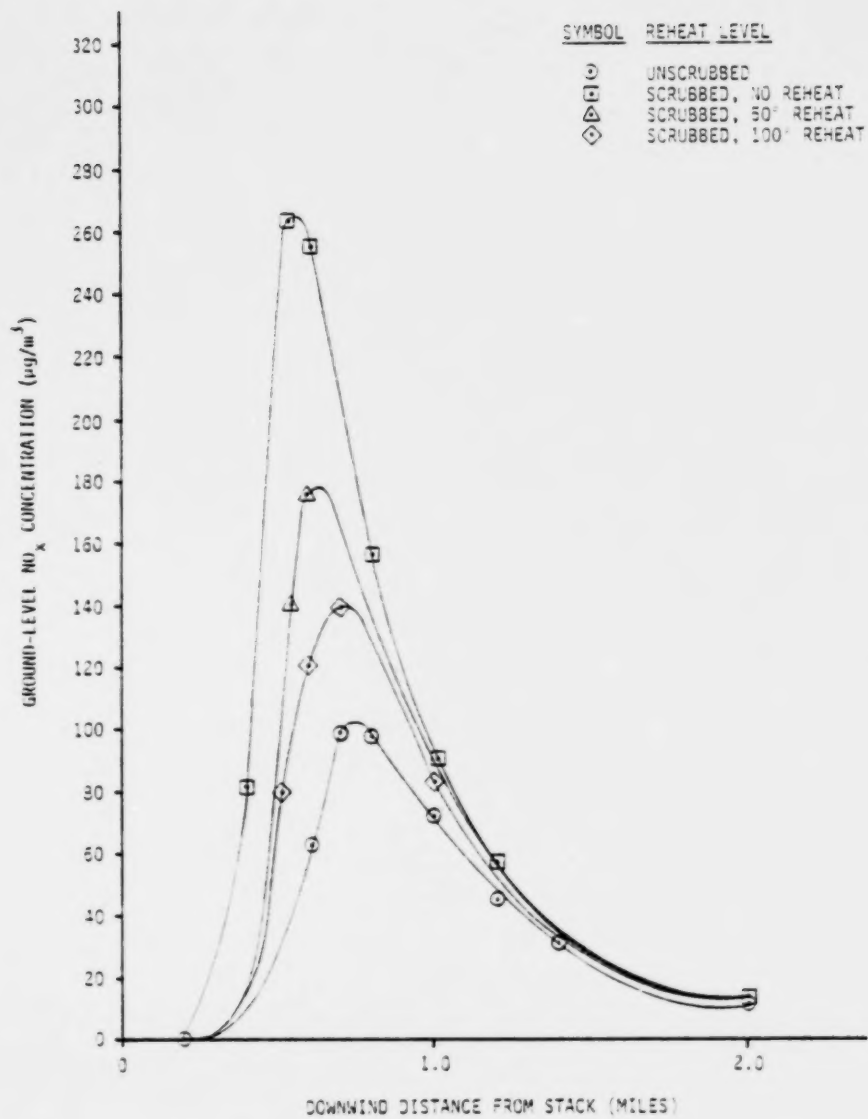


Figure 14. Model-predicted three-hour, ground-level NO_x concentration downwind of the stack for an unstable atmosphere (wind speed = 5 mph).

- (5) The maximum ground-level concentration of NO_x resulting from the scrubbed plume (with 100°F reheat) is approximately 40 percent greater than the maximum NO_x ground-level concentration exhibited by the unscrubbed plume.

Similar effects (observed for NO_x) would be anticipated for other pollutants not removed in the scrubbing process.

The meteorological conditions assumed for the neutral atmosphere modeling were an 18-mph speed, a 60°F ambient air temperature, and an ambient temperature gradient of $-5.4^\circ\text{F}/10^3$ ft. The results predicted for the neutral atmosphere are illustrated in Figures 15 and 16 and show the same general trends in SO_2 and NO_x reduction that were shown for the unstable atmosphere. Both the SO_2 and NO_x maximum ground-level concentrations for the neutral atmosphere are considerably less than those exhibited in an unstable atmosphere.

It should be noted that other techniques can be used to reduce ground-level pollutant concentrations. For instance, the use of a more efficient scrubber would reduce the ground-level SO_2 concentration. The impact of improved scrubber efficiency on the maximum ground-level SO_2 concentration for a neutral atmospheric stability is shown in Table 32. The data in this table show that the effect of a given level of reheat on ground-level SO_2 concentration is diminished as the SO_2 removal efficiency is increased. Since NO_x is not removed by the scrubbing process, the same ground-level NO_x concentration would be exhibited regardless of the SO_2 removal efficiency.

An increased stack height can also reduce the ground-level pollutant concentrations. Data presented in Table 33 show the impact of increased stack height on maximum ground-level SO_2 and NO_x concentrations. From these data it can be seen that the reduction in ground-level pollutant concentrations that is gained by the progressive addition of reheat to a scrubbed flue gas is diminished at an increased stack height.

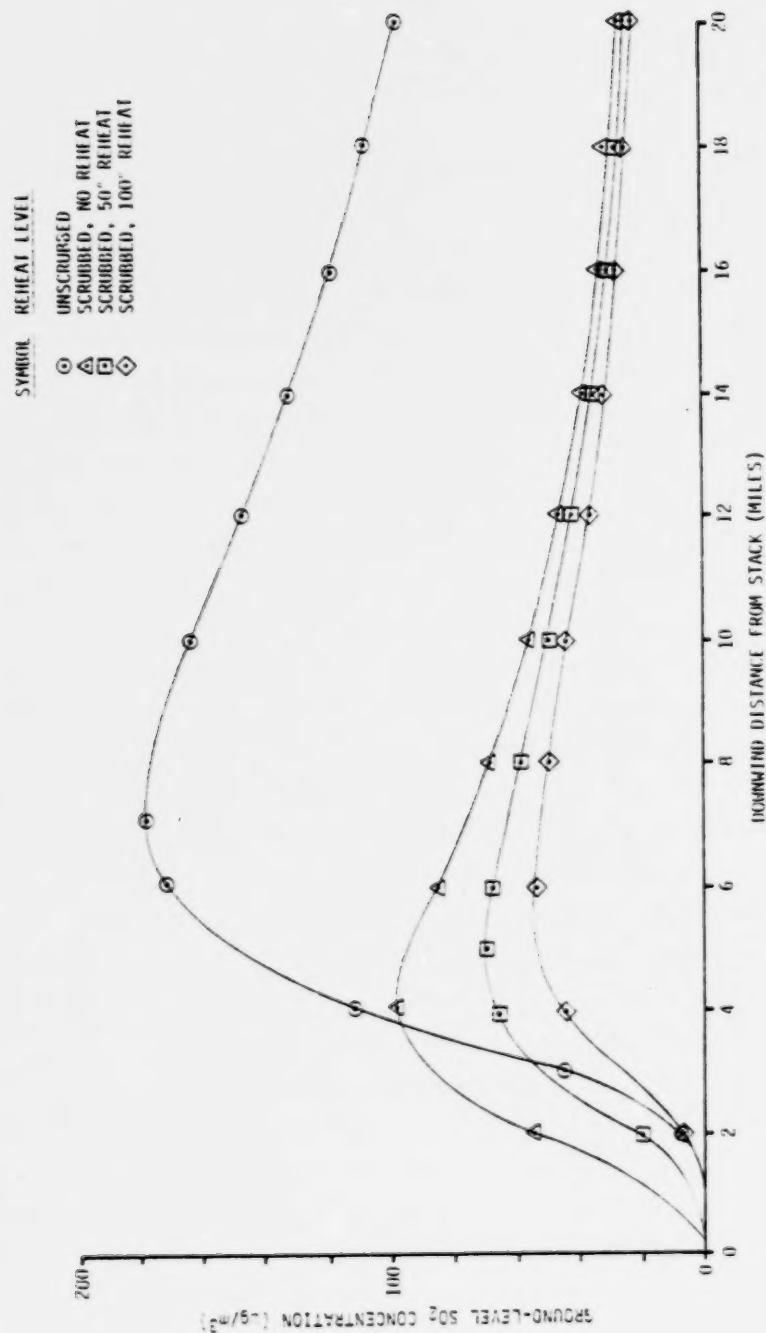


Figure 15. Model-predicted three-hour, ground-level SO₂ concentration downwind of the stack for a neutral atmosphere (wind speed = 18 mph).

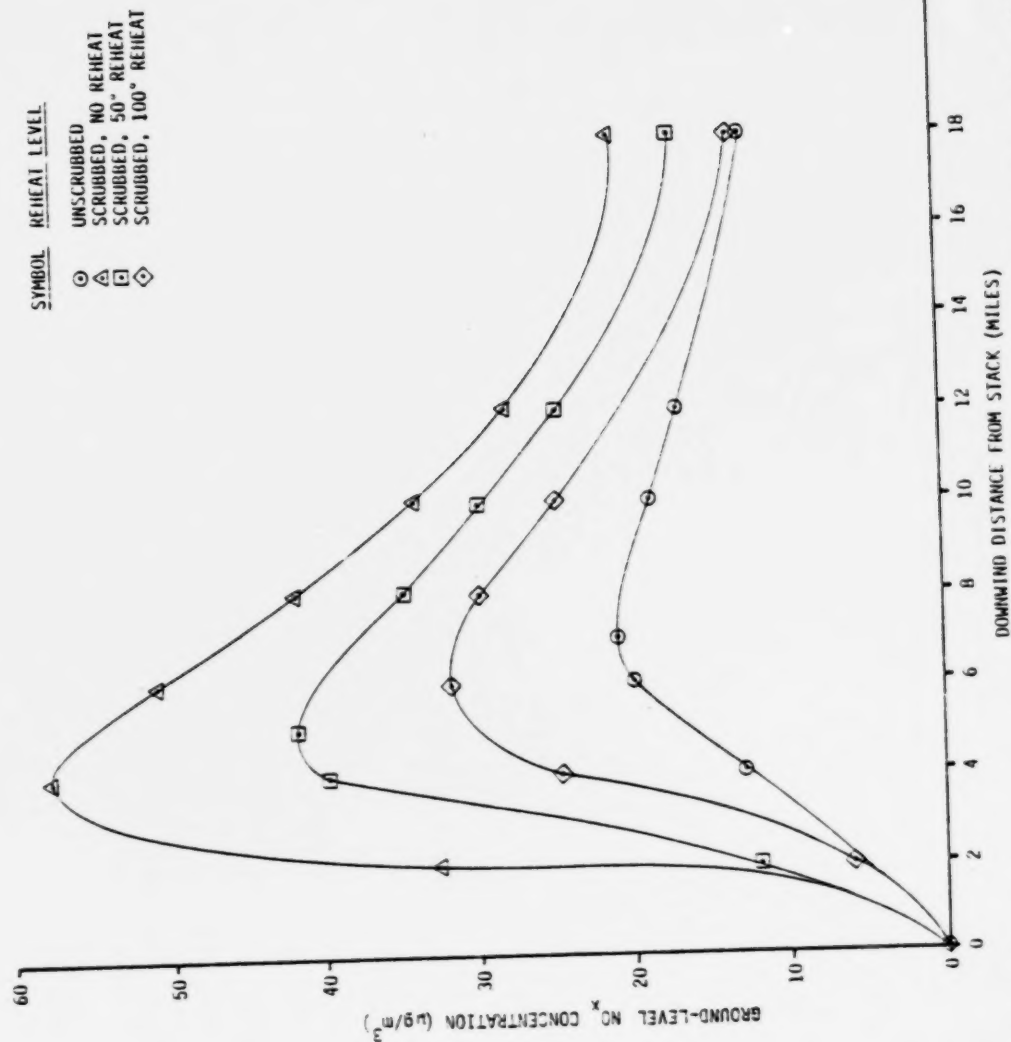


Figure 16. Model-predicted three-hour, ground-level NO_x concentration downwind of the stack for a neutral atmosphere (wind speed = 18 mph).

TABLE 32. IMPACT OF SO₂ REMOVAL EFFICIENCY ON MAXIMUM THREE-HOUR GROUND-LEVEL SO₂ CONCENTRATIONS

SO ₂ Removal Efficiency (%)	Scrubbing-Reheat Level	Maximum Ground Level SO ₂ Concentrations	
		µg/m ³	% of unscrubbed
70	Unscrubbed	180	100
	Scrubbed with no reheat	147	82
	Scrubbed with 50°F reheat	105	58
	Scrubbed with 100°F reheat	84	47
80	Unscrubbed	180	100
	Scrubbed with no reheat	98	54
	Scrubbed with 50°F reheat	70	39
	Scrubbed with 100°F reheat	55	31
90	Unscrubbed	180	100
	Scrubbed with no reheat	49	27
	Scrubbed with 50°F reheat	35	19
	Scrubbed with 100°F reheat	28	16

Bases:

- (1) Neutral atmospheric stability
- (2) 18-mph wind speed
- (3) 500-MW plant
- (4) 300-foot stack height
- (5) 30.6-foot stack diameter
- (6) Stack gas velocities
 - (a) unscrubbed - 35.0 ft/sec
 - (b) scrubbed - 28.7 ft/sec
 - (c) scrubbed with 50°F reheat - 31.1 ft/sec
 - (d) scrubbed with 100°F reheat - 33.5 ft/sec
- (7) Unscrubbed stack gas temperature - 300°F
- (8) Scrubbed stack gas temperature (with no reheat) - 129°F

TABLE 33. IMPACT OF STACK HEIGHT ON MAXIMUM THREE-HOUR GROUND-LEVEL POLLUTANT CONCENTRATIONS

Stack Height (ft)	Scrubbing-Reheat Level	Maximum Ground Level		Maximum Ground Level	
		SO ₂ Concentration µg/m ³	% of unscrubbed	NO _x Concentration µg/m ³	% of unscrubbed
300	Unscrubbed	180	100	21	100
	Scrubbed with no reheat	98	54	58	276
	Scrubbed with 50°F reheat	70	39	42	200
	Scrubbed with 100°F reheat	55	31	32	152
600	Unscrubbed	78	100	9	100
	Scrubbed with no reheat	30	38	18	200
	Scrubbed with 50°F reheat	24	31	14	156
	Scrubbed with 100°F reheat	20	26	12	133

Bases:

- (1) Neutral atmospheric stability
- (2) 18-mph wind speed
- (3) 500-MW plant
- (4) Atmospheric temperature is assumed to be 60°F.
- (5) 80 percent SO₂ removal
- (6) 30.6-foot stack diameter
- (7) Stack gas velocities
 - (a) unscrubbed - 35.0 ft/sec
 - (b) scrubbed - 28.7 ft/sec
 - (c) scrubbed with 50°F reheat - 31.1 ft/sec
 - (d) scrubbed with 100°F reheat - 33.5 ft/sec
- (8) Unscrubbed stack gas temperature - 300°F
- (9) Scrubbed stack gas temperature (with no reheat) - 129°F

Annual average concentrations were also estimated; however, these concentrations were estimated with the Gauss/X-Star Modeling program which utilizes the algorithm developed by Busse and Zimmerman in 1973.²⁶ The results of the annual average modeling are given in Table 34. These results show that the annual average SO₂ concentration is progressively reduced by scrubbing and the addition of 50°F and 100°F of reheat. As expected, the ground-level NO_x concentration is increased by scrubbing. It is also apparent that 50°F and 100°F of reheat reduces ground-level NO_x but do not reduce the NO_x concentration to the level exhibited by unscrubbed flue gas. It should be noted that the concentrations of both NO_x and SO₂ are well below current applicable air quality standards.

TABLE 34. MAXIMUM ANNUAL AVERAGE POLLUTANT CONCENTRATIONS

	SO ₂ μg/m ³	NO _x μg/m ³	Distance from stack (km)
Unscrubbed	9.0	1.1	7.9
Scrubbed, no reheat	4.3	2.4	4.5
Scrubbed, 50°F reheat	2.8	1.6	6.8
Scrubbed, 100°F reheat	2.3	1.3	6.8

Bases: Same as given in Table 32.

Based on the predictions of the plume models, it is concluded that reheating the flue gas can significantly reduce the ground-level pollutant concentrations that occur when a flue gas is scrubbed. However, other techniques, such as improved SO₂ removal efficiency and increased stack height, can also reduce the ground-level pollutant concentrations. Consequently, the selection of any technique should be based on a technical and economic assessment of all available alternatives.

Impact of Climate on Ground-Level SO₂ Concentration

The impact of reheat on ground-level SO₂ concentrations at various climatic conditions was also investigated. In this analysis the effect of scrubbing and various reheat temperatures on ground-level SO₂ concentrations at ambient air temperatures of 70°F (summer), 40°F (spring-fall), and 10°F (winter) was determined. The results of this study are presented in Table 35. These data show that:

- (1) The highest maximum ground-level concentrations occur in the summer.
- (2) A given level of reheat will have more impact (in terms of reducing ground-level concentrations) in the summer than in the cooler seasons.

Impact of Indirect Hot Air Reheat Configuration on Ground-Level SO₂ Concentrations

Since the indirect hot air configuration dilutes the flue gas as well as heats it, it is of interest to determine the effects on ground-level pollutant concentrations of reheating the flue gas to the same exit temperature by using the inline and indirect hot air reheat configurations.

As shown in Appendix A, the time-averaged ground-level SO₂ concentration as proposed by Turner²⁷ is given by the following expression:

$$\chi(x,y,H) = \frac{Q}{\pi u \sigma_y \sigma_x} \exp \left[-\frac{1}{2} \left(\frac{y}{\sigma_y} \right)^2 - \frac{1}{2} \left(\frac{H}{\sigma_z} \right)^2 \right] \quad (3)$$

where

- χ = the pollutant concentration (lb/ft³)
- x = distance downwind from stack (ft)
- y = radius of the plume at (x,H)
- H = height of plume centerline relative to ground (ft)
- u = wind speed (ft/min)

TABLE 35. SEASONAL EFFECT OF REHEAT ON GROUND-LEVEL SO₂ CONCENTRATION

Ambient Air Temperature	Scrubbing and Degree of Reheat	Maximum Ground Level SO ₂ Concentration (μg/m ³)	Distance at Which Maximum SO ₂ Occurs (Km)	% SO ₂ Reduction Compared to Unscrubbed
10°F, Winter	Unscrubbed	117	47	0
	Scrubbed with 25 reheat	28	26	76
	Scrubbed, 25°F reheat	24	29	80
	Scrubbed, 50°F reheat	20	31	83
	Scrubbed, 100°F reheat	16	37	86
40°F, Spring-Fall	Unscrubbed	131	43	0
	Scrubbed with 25 reheat	35	22	73
	Scrubbed, 25°F reheat	29	26	78
	Scrubbed, 50°F reheat	24	29	81
	Scrubbed, 100°F reheat	19	34	86
70°F, Summer	Unscrubbed	148	40	0
	Scrubbed with 25 reheat	47	19	69
	Scrubbed, 25°F reheat	36	22	75
	Scrubbed, 50°F reheat	30	25	80
	Scrubbed, 100°F reheat	22	30	85

Bases:

- (1) 15-mph wind speed
- (2) Neutral atmospheric stability
- (3) 600-foot stack height
- (4) 24.6-foot stack diameter
- (5) 500-TW plant (same coal as in Table 27)
- (6) One-hour average concentrations
- (7) 80 percent SO₂ removal in scrubber
- (8) Stack gas velocities
 - (a) unscrubbed - 47.2 ft/sec
 - (b) scrubbed - 41.9 ft/sec
 - (c) scrubbed with 25°F reheat - 43.8 ft/sec
 - (d) scrubbed with 50°F reheat - 45.6 ft/sec
 - (e) scrubbed with 100°F reheat - 49.1 ft/sec

Q = pollutant source strength (lb/min)
 σ_y = horizontal dispersion coefficient (ft)
 σ_z = vertical dispersion coefficient (ft)

In this expression, only H , the height of the plume centerline, is affected by the reheat method. The height of the plume centerline or plume rise is expressed as:

$$H = h + \frac{1.6F^{1/3} x^{2/3}}{u} \quad (9)$$

where H = height of plume centerline
 h = stack height (ft)
 F = buoyancy flux (ft^4/min^3)
 x = downwind distance (ft)
 u = wind speed (ft/min)

Reheat affects the plume rise through the buoyancy flux variable which can be expressed as:

$$F = g V_s R_s^2 \left(\frac{T_s - T_a}{T_s} \right) \quad (10)$$

where V_s = velocity of flue gas in the stack (ft/min)
 g = local acceleration due to gravity (ft/min^2)
 R_s = stack radius at exit (ft)
 T_s = stack exit temperature ($^{\circ}\text{R}$)
 T_a = ambient temperature ($^{\circ}\text{R}$)

The term $V_s R_s^2$ is directly proportional to the volumetric flow rate of the gas at the stack exit. If the same stack exit temperature is obtained with both the inline and indirect hot air methods, then F will be greater for the indirect hot air system. Looking at Equations 8 and 9, a higher F value will result in a higher H value and therefore, a lower x value.

Assuming (1) the heat input with each reheat configuration (inline and indirect hot air) are equal, (2) the specific heats of air and flue gas are equal, (3) the stack diameter is the same for each configuration, and (4) the gases can be described by the ideal gas law; it can be shown that

$$F_{\text{indirect}} = F_{\text{inline}}$$

This result indicates that as far as ground-level pollutant concentrations are concerned, the dilution effect of hot air injection makes the inline and indirect systems comparable at the same heat input.

APPLICABILITY OF BYPASS REHEAT

The utilization of bypass reheat is limited by pollutant emission constraints. Consequently, the quantity of flue gas bypassed and the corresponding degree of reheat are dependent on the SO₂ emission standards and the attainable SO₂ removal efficiency in the scrubber. The restrictions imposed by SO₂ regulations on the use of bypass reheat are discussed for two cases:

- (1) Old NSPS for steam electric plants
- (2) Current NSPS for steam electric plants

Old New Source Performance Standards for SO₂ Emissions

Until June 11, 1979 the NSPS for SO₂ emissions from coal-fired steam electric plants allowed the emission of 1.2 lb of SO₂/10⁶ Btu fuel input. Based on this standard the fraction of unscrubbed flue gas that could be bypassed can be determined with the following expression.

$$FBP = 1 - \frac{1}{E} + \frac{1.2}{2WSE} \quad (12)$$

where: FBP = fraction of total flue gas flow that can be bypassed

E = SO₂ removal efficiency capability of the scrubber
(fraction)

W = weight of fuel required for 10⁶ Btu (lb)

S = weight fraction of sulfur in the fuel

An approximation of the allowable fraction of flue gas which could be bypassed under these standards is presented below for several different coal qualities (assuming a 300°F unscrubbed stack gas temperature, a 130°F scrubber exit gas temperature, and a scrubber with a maximum capability of 90 percent SO₂ removal).

Coal Quality		Fraction of Flue Gas That Could be Bypassed	Approximate Stack Exit Temperature, °F
Heating Value Btu/lb	Sulfur Content Wt %		
8,500	0.5	1.00*	300
10,500	1.5	0.35	185
10,500	3.0	0.12	145

As shown, a substantial fraction of the flue gas could be bypassed when firing low to medium sulfur (0.5-1.5 Wt %) coals.

Current New Source Performance Standards

The New Stationary Source Performance Standards for electric utility steam generating units (published in 6/11/79 Federal Register) require scrubbers with ≥ 70 percent SO₂ removal efficiency for all coals. Included in the standard is a maximum emission limitation of 1.2 lb SO₂/10⁶ Btu fuel input. This standard provides a sliding scale for required SO₂ removal with high sulfur coals requiring about 90 percent removal and very low sulfur coals requiring 70 percent SO₂ removal. An approximation of the

*No scrubber required

maximum stack temperature that can be obtained with bypass reheat is given below (assuming a 300°F unscrubbed stack gas temperature, a 130°F scrubber exit temperature, and a scrubber with an average capability of 90 percent SO₂ removal).

<u>Average Required SO₂</u> <u>Removal Efficiency, %</u>	<u>Fraction of Flue Gas</u> <u>That Could Be Bypassed</u>	<u>Approximate Stack Exit</u> <u>Temperature, °F</u>
70	0.22	165
80	0.11	147
90	0.00	130

Therefore about 35°F is the maximum stack gas reheat level that can be achieved under current electric utility standards and this will only apply for very low sulfur coals (unless extremely high SO₂ removal standards are employed). It is recognized that the above analysis is quite simplistic and does not consider the compliance requirements of the NSPS. Therefore the potential reheat levels shown above are somewhat higher than an operating plant could realistically achieve.

Energy Balance

Once the maximum allowable bypass fraction has been determined, the degree of reheat attainable can be calculated using the following energy balance (as long as $T_e \geq$ dewpoint of the gas exiting the stack and all of the mist carry-over is evaporated):

$$\begin{aligned}
 m_{BP} C_{p,BP} (T_{BP} - T_e) &= m_f C_{p,f} (T_e - T_{fs}) + m_w (h_{w,s} - h_{w,fs}) \\
 &+ \frac{g}{g_c j} (\Delta Z) (m_{BP} + m_f + m_w) + \frac{m_f}{2g_c j} (v_{f,s}^2 - v_{f,fs}^2) + \frac{m_w}{2g_c j} (v_{w,s}^2 - v_{w,fs}^2) \\
 &+ \frac{m_{BP}}{2g_c j} (v_{f,s}^2 - v_{BP}^2) - Q_f + Q_{t1} - Q_R
 \end{aligned} \tag{13}$$

where:

- m_{BP} = mass flow rate of bypassed flue gas (lb/hr)
- $C_{p,BP}$ = specific heat of the bypassed flue gas (Btu/lb-°F)
- T_{BP} = temperature of bypassed flue gas (°F)
- T_e = temperature of gas exiting the stack (°F)
- m_f = mass flow rate of gas exiting the scrubber (lb/hr)
- $C_{p,f}$ = specific heat of gas exiting the scrubber (Btu/lb-°F)
- T_{fs} = temperature of gas exiting the scrubber (°F)
- m_w = mist carry-over (lb/hr)
- $h_{w,s}$ = enthalpy of vaporized entrained mist at the stack outlet (Btu/lb)
- $h_{w,fs}$ = enthalpy of the entrained mist exiting the scrubber (Btu/lb)
- g = acceleration of gravity (ft/sec²)
- g_c = conversion factor (ft-lb_m/sec²-lb_f)
- j = mechanical equivalent of heat (778 ft-lb_f/Btu)
- Δz = net elevation traversed by flue gas (approximately the difference in duct and stack outlet height) (ft)
- $v_{f,s}$ = velocity of the flue gas at the stack outlet (ft/sec)
- $v_{f,fs}$ = velocity of the flue gas at the scrubber outlet (ft/sec)
- $v_{w,s}$ = velocity at the stack outlet of the vaporized entrained mist (ft/sec)
- $v_{w,fs}$ = velocity at the scrubber outlet of the entrained mist (ft/sec)
- v_{BP} = velocity of bypassed flue gas prior to mixing with scrubbed flue gas (ft/sec)
- Q_f = heat resulting from the work of compression by an induced draft fan (Btu/hr)
- Q_{tl} = total heat lost from the duct and stack (Btu/hr)
- Q_R = heat input using supplemental reheater (Btu/hr)

Assuming the sensible heat required for the vaporized liquid is negligible and the required heat input associated with the kinetic and potential energy terms is small, the energy balance equation is reduced to:

$$m_{BP} C_{p,BP} (T_{BP} - T_e) = m_f C_{p,f} (T_e - T_{fs}) + m_w \lambda_w + Q_{tl} - Q_f - Q_R \quad (14)$$

As indicated above, if an insufficient fraction of the flue gas can be bypassed to effect the required reheat, then a supplemental reheater could be used to heat the scrubbed gas further. This could be accomplished in one of two ways:

- (1) The reheater could be placed in the bypassed gas circuit. Since this gas would be relatively dry and noncorrosive, the reliability problems incurred with an inline system would not be expected.
- (2) The reheating could be done conventionally (inline, indirect hot air, exit gas recirculation) for the combined bypass and scrubber exit gases.

In summary, bypass reheat is the most economical method available for stack gas reheat since waste heat is utilized and expensive heat exchange equipment is not required. SO_2 emission standards will restrict the use of bypass reheat somewhat. However, it is expected that industry will still utilize bypass reheat to the degree allowed under current regulations. Supplemental heat in the manner described above will permit reheat of stack gases to any level desired.

SECTION 7

STACK GAS REHEAT ECONOMICS

The capital and operating costs of reheating a flue gas from a new 500-MW power plant were estimated for the inline, indirect hot air, direct combustion, and exit gas recirculation reheat configurations. The stack gas was heated 50°F above the scrubber exit temperature. These costs were estimated (in mid-1978 dollars) using the following approach:

- (1) A steam cycle for a new 500-MW power plant was developed; those steam levels that could be used for reheat were identified and their respective costs estimated. A cost for hot water from the steam cycle was also estimated.
- (2) The reheat exchangers were sized and their installed costs (capital investment) estimated.
- (3) The capital investment for direct combustion reheat systems was estimated based on published information for similar facilities.
- (4) The operating costs of the various reheat configurations were estimated.

The cost of using bypass reheat was not estimated since current SO₂ emission standards for new coal-fired power plants significantly restrict its use. Fifty degrees (50°F) of reheat cannot be obtained using bypass reheat* unless a supplemental reheater is used (see Section 6 for details). However, the cost of bypass reheat is very low compared to other reheat methods (no external energy and heat exchange equipment required). Therefore it is anticipated that industry will continue to use bypass reheat to the extent permitted by environmental regulations (see Section 6) and maximum scrubber SO₂ removal capability.

*Under the recently promulgated (June 11, 1979 Federal Register) NSPS for utility boilers.

After estimating the capital and operating costs of the various configurations, an annual revenue requirement (consisting of operating and capital investment-related costs) was calculated for each configuration. This annualized cost was used to compare the costs of all the cases analyzed in this study.

AVAILABILITY AND COST OF STEAM

The initial step in estimating the costs of the various SGR configurations was to identify the steam levels that can be used for reheat and estimate their respective costs.

- (1) A steam cycle was developed for a "hypothetical" new 500-MW power plant in which no reheat is used. This steam cycle was considered to be the base case.
- (2) Several steam levels (extraction steam from the turbine) were identified as applicable for use as a reheat medium.
- (3) The impact (on the base case steam cycle) of using each of the applicable steam levels for reheat was determined. Based on this effect, the cost of each steam level was estimated.

Steam Cycle Development and Applicability of Different Quality Steams to SGR

The development of the base case steam cycle is presented in detail in Appendix C. In this steam cycle, nine levels of steam are hypothetically available for use as the heating medium in a reheat system. These steam conditions are presented in Table 36. Although throttle steam (at the turbine inlet) could be used for reheat, it is assumed that this steam would be too valuable to be used for reheat in a new power plant. The suitability of the other steam levels in Table 36 for use in SGR was based on the criteria that (1) the steam temperature must be greater than the flue gas temperature, and (2) the steam pressure should be greater than the flue gas

pressure. The latter criterion insures that if a leak were to develop in the exchanger the steam would leak into the flue gas instead of the flue gas leaking into the steam system. Therefore, steam with pressure less than about 15 psia was considered unsuitable. Steam ranging in pressure from 15 psia to high pressure turbine exhaust conditions was considered applicable. For the base case steam cycle, applicable steam pressures ranged from 16 to 600 psia.

TABLE 36. AVAILABLE STEAM CONDITIONS IN THE BASE CASE STEAM CYCLE

Description	Steam Conditions		Applicability as Reheat Steam
	Pressure (psia)	Temperature (°F)	
Throttle steam	2600	1000	OK but very expensive
Extraction steam	600	639	Acceptable
Extraction steam	310	870	Acceptable
Extraction steam	165	745	Acceptable
Extraction steam	83	610	Acceptable
Extraction steam	39	475	Acceptable
Extraction steam	16	344	Acceptable
Extraction steam	5.6	208	Not acceptable
Turbine exhaust	1.7	120	Not acceptable

Each of the applicable steam levels was analyzed to determine how its use as reheat steam would affect the base case cycle. The steam cycle was adjusted to provide the required quantity of reheat steam while maintaining the 500-MW (net) output and constant enthalpy for all streams. These analyses provided the following data for each steam level evaluated as reheat steam:

- (1) Additional plant fuel requirements
- (2) Change in plant condenser heat rejection requirements
- (3) Change in steam flows in turbine and feedwater heaters

The primary objective of this economic analysis was to develop and illustrate a methodology for estimating the costs of stack gas reheat systems. The results can be used to illustrate the cost trends (not a rigorous calculation) associated with the use of low through high pressure extraction steams. While a particular steam cycle was chosen for analysis, the trends should be similar for any steam cycle.

Cost of Various Steam Levels

Although it is recognized that steam costs are very site specific, the relative costs of the different steam levels are expected to be similar for other steam cycles. Consequently, the trends exhibited by the steam costs developed in this section are considered to be applicable to other systems.

The annualized cost (\$/lb steam) associated with using each of the applicable steam levels for reheat (from the base case steam cycle) is also developed in Appendix C. These annualized costs (presented in Table 37) include the capital-related and operating costs incurred in producing the reheat steam. To develop the dry, saturated steam costs, it was assumed that the superheated steam was desuperheated by spraying condensate into the steam. Some users of reheat have indicated that the use of dry, saturated steam in SGR would result in more reliable operation compared to operation with a highly superheated steam. Therefore, costs for dry, saturated steam at the same pressure are also presented in Table 37.

It should be noted that the steam costs presented in Table 37 are representative of a new 500-MW power plant with scrubber and reheat. If a reheat system were retrofitted to an existing power plant, different results would be expected. Depending on site specific factors for a particular retrofit situation, steam costs may range from low (if the steam cycle can easily be readjusted such that the plant power output is unaffected) to high (if the power output is significantly reduced).

TABLE 37. COST (1978 \$) OF VARIOUS STEAM LEVELS FOR REHEATING FLUE GAS*

Extraction Steam (Superheated) and Hot Water				Dry, Saturated Steam			
Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Cost (\$/1000 lb)	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Cost** (\$/1000 lb)
600	639	1314	1.95	600	486	1204	1.69
310	870	1457	2.27	310	420	1204	1.73
165	745	1396	1.93	165	366	1196	1.57
83	610	1335	1.60	83	319	1184	1.37
39	475	1274	1.22	39	266	1169	1.10
16	344	1213	0.83	16	216	1152	0.78
Hot Water							
165	366	399	0.24	-	-	-	-

*For small quantities of reheat steam (\$/1000 lb) in a new 500-MW power plant. Coal cost is \$1/10⁶Btu.

**Saturated steam is desuperheated by spraying condensate into superheated steam. It was assumed that the costs of the equipment required (pump, desuperheating vessel, and piping) to desuperheat the steam are negligible compared to the cost of the steam. Therefore, the cost of saturated steam was estimated using the following equation:

$$\frac{\$}{1000 \text{ lb}} \left(\begin{array}{c} \text{dry,} \\ \text{saturated} \\ \text{steam} \end{array} \right) = \frac{h_{\text{dry, saturated steam}} - h_{\text{saturated liquid}}}{h_{\text{superheated steam}} - h_{\text{saturated liquid}}} \times \$/1000 \text{ lb} \left(\begin{array}{c} \text{superheated} \\ \text{steam} \end{array} \right)$$

REHEAT EXCHANGER SIZING

After estimating the costs for various levels of steam (for a new power plant), reheat exchangers were sized on the basis of using superheated and saturated steam. The initial step in each case was the determination of the overall heat transfer coefficients. These coefficients are highly dependent on the resistance to heat transfer due to fouling of the tubes. Industry data indicated that inline exchangers are fouled by solids resulting from evaporation of scrubbing liquor carried-over from the mist eliminator as well as residual fly ash in the flue gas. However, no specific information about the resistance to heat transfer due to fouling was obtained. In the case of mist carry-over, it is expected that the front tubes will foul badly while the rear tubes will remain clean. Therefore the lead tubes will have to be cleaned on a more frequent basis. Thus, safety factors should probably be added as excess tubes rather than by estimation of a fouling factor. The safety factors incorporated in the reheater designs are presented in Table 38.

For both superheated and saturated steam, the film heat transfer coefficient for steam is much greater than the flue gas film coefficient. Consequently, the flue gas film was considered to be the controlling resistance to heat transfer in the exchanger and therefore, to have the greatest impact on the overall heat transfer coefficient. An analysis of the flue gas film coefficient for reheat exchangers showed that this coefficient is dependent on: 1) flue gas properties, velocity, and temperatures (entering and exiting the exchanger), 2) tube spacing, and 3) the pressure drop experienced by the flue gas in the exchanger. A calculational scheme relating these various parameters, the flue gas film heat transfer coefficient, and the resulting exchanger heat transfer area was developed. The expressions used in the development of this calculational scheme are presented in Appendix D.



TABLE 38. CAPITAL AND OPERATING COST BASES* USED TO DEVELOP ECONOMICS OF VARIOUS REHEAT CONFIGURATIONS

Exit	Bases Used in Study	Remarks
	<u>Capital Cost Related Bases</u>	
Exchanger Tube Metallurgy	Carbon steel tube metallurgy was evaluated for inline, BGM, and indirect hot air injection. Stainless steel Type 316 and Inconel 625 were also evaluated for inline systems.	
Required Exchanger Area		See Appendix D for other bases used in exchanger sizing.
• Inline Reheat	To provide a safety factor for plugging and fouling, a 3" center-center tube spacing was used and the calculated exchanger surface area was increased by 25%.	
• Exit Gas Recirculation Reheat	To provide a safety factor for plugging and fouling, a 3" center-center tube spacing was used and the calculated exchanger surface area was increased by 25%.	
• Indirect Hot Air Reheat	A 1.5" center-center tube spacing was used and a 10% safety factor was incorporated into the exchanger surface area.	
Exchanger Tube Life and Cost**		See Appendix E for development of exchanger tube life and cost.
• Inline Reheat		
--carbon steel	\$20/ft ² ; 0.10" wall thickness, 2-yr life	
--316L stainless steel	\$39/ft ² ; 0.10" wall thickness, 4-yr life	
--Inconel 625	\$70/ft ² ; 0.10" wall thickness, 8-yr life	
• Indirect Hot Air Reheat		
--carbon steel	\$11/ft ² ; 0.05" wall thickness, 10-yr life	
• Exit Gas Recirculation Reheat		
--carbon steel	\$20/ft ² ; 0.10" wall thickness, 5-yr life	
Primary and Auxiliary Fan Sizing and Costs	Computer program used to size and cost fans.	See Appendix D for bases of computations.
Stack Cost	Base case cost of stack is 2.6MM\$ for a 300' stack with a 12.4' diameter.	The indirect hot air configuration increases volumetric flow rate of flow gas; if the stack gas velocity is to remain the same, the diameter of a proposed stack would have to be increased. Consequently, its cost would, also, increase. See Appendix D for detailed development.
Soot Blower Costs	Base cost = \$1700/each	See Appendix D for development of bases.
Direct Labor and Materials Cost (Installation of reheat exchanger)	\$89,500 plus \$13.40/ft ² of exchanger surface area (Ref. 33).	See Appendix E for development of bases.
Indirect Costs	Equals 45% of total direct costs (equipment costs plus direct labor and materials cost)	See Appendix E for development of bases.
	<u>Operating Cost Related Bases</u>	
Steam Costs	Steam costs given in Table 37	See Appendix C for development.
Power Costs	\$0.0314/kwh	See Appendix E for development.
Maintenance Costs	Based on direct labor and materials cost, capital cost of exchanger, and tube life	See Appendix E for development.
Depreciation Cost	Based on 25-yr straight-line depreciation	
	<u>Annualized Cost of Configuration</u>	
Annual Revenue Requirement	ARR = $N \times C/M \times (0.095 \text{ yr}^{-1}) C$ ARR = Annual Revenue Requirement N = Operating Costs (\$/yr) C = Capital Investment (\$) M = Equipment Life (yrs)	The ARR reflects the capital and operating cost components associated with each configuration. For purposes of this study, a 25-yr straight-line equipment depreciation was used. See Appendix C for economic bases development.
	<u>Other Bases</u>	
Cost of Downtime	No additional cost has been included for lost power generation capability if reheater downtime causes the boiler to reduce load or shut down.	

*All costs are mid-1978.

**Exchanger cost, P.O.B. plant. All tubes are 1 inch O.D.

It should be noted that for the exchangers in the inline and exit gas recirculation reheat configurations, a triangular pitch exchanger was selected with a tube spacing of 3 inches center-center (or 2 inches between tubes) because industry data show pluggage is common at lesser tube spacings. The overall heat transfer coefficients for the condensing portion* of these exchangers were calculated to be 17 to 32 Btu/hr-ft²-°F, while the coefficients in the desuperheat section* of these exchangers ranged from 16 to 19 Btu/hr-ft²-°F. For the exchangers in the indirect hot air reheat configuration, a tube spacing of 1-1/2 inches center-center (0.5 inch between tubes) was assumed. This reflects the clean conditions expected to exist in these exchangers. The overall heat transfer coefficients for the condensing portion* of these exchangers were calculated to be 24 to 42.5 Btu/hr-ft²-°F. The value of the overall coefficient in the desuperheat section* ranged from 20.9 to 27.8 Btu/hr-ft²-°F.

COSTS OF VARIOUS REHEAT CONFIGURATIONS

After the exchangers for the various configurations analyzed in this study were sized, the following approach was used to estimate the costs of these configurations.

- (1) The capital investment and operating costs associated with the inline, indirect hot air, and exit gas recirculation configurations were estimated using each level of saturated steam shown in Table 36.
- (2) One case developed for each configuration in step (1) of this approach was selected as a "base case."
- (3) Various parameters (exchanger pressure drop, fan position, etc.) of each configuration's base case were changed in order to determine the impact of each parameter on the costs. Also, the impacts of using superheated steam and different tube materials were investigated.

*Exchangers using superheated steam were designed with separate desuperheat and condensing sections. Exchangers using dry, saturated steam would have overall heat transfer coefficients similar to the condensing section coefficients.

- (4) The capital investment and operating costs associated with direct combustion reheat were estimated.
- (5) An annual revenue requirement (ARR) was calculated based on the capital investment and operating costs so that the costs of the various systems could be compared.

The technical and economic bases used to develop the overall economics of the different reheat configurations are presented in Tables 38 and 39, and Figure 17. For this study, the flue gas was reheated by a nominal 50°F (the level indicated most by industrial users in the survey-see Section 5).

Economics of Inline Reheat Configuration

To estimate the costs of reheating the flue gas from a new 500-MW plant (described in Table 39) with an inline reheater and various dry, saturated steam levels, the following assumptions were made:

- (1) The flue gas was reheated by 50°F, which is equivalent to a heat input of about 66.8×10^6 Btu/hr.
- (2) It was assumed that no mist entrainment was present in the flue gas and that no heat was lost from the flue gas through the walls of the duct or stack.

Initially, only a forced draft primary fan configuration (Figure 17b) having an overall pressure drop of 40 inches of water and the use of dry, saturated steam were considered. The capital and operating costs associated with using 600 psia, saturated steam as the heating medium in this configuration are presented in Table 40. Cost summary sheets for the other saturated steam levels analyzed are presented in Tables E-1 through E-7 in Appendix E.

Table 40 shows that the capital requirement for this configuration consists of the direct and indirect costs that are necessary to make an inline reheat system operational. In addition to the reheat equipment, incremental capital investments are included for other equipment which must increase in capacity if a reheat system were to be incorporated into

TABLE 39. PLANT CHARACTERISTICS AND FGD CONFIGURATIONS USED TO DEVELOP ECONOMICS OF VARIOUS REHEAT CONFIGURATIONS

Power Plant Bases, Fuel and Flue Gas Compositions

Power Plant Characteristics	Coal Composition		Flue Gas Composition Entering Scrubber		
	Component	Weight Percent	Component	Volume Percent	lb/hr
• New, 500-MW	C	57.56	N ₂	73.76	3,450,000
• 9,000 Btu/kWh	H	4.14	O ₂	4.83	258,200
Heat Rate	N	1.29	CO ₂ *	12.31	904,200
• Flue gas temperature entering scrubber is 300°F	O	7.00	SO ₂	0.24	23,130
	S	3.12	SO ₃	0.0024	317
	Cl	0.15	NO _x	0.06	3,022
	H ₂ O	10.74	HCl	0.01	661
	Ash	16.00	H ₂ O	8.79	264,500
	Heat Content	10,500 Btu/lb			4,906,030

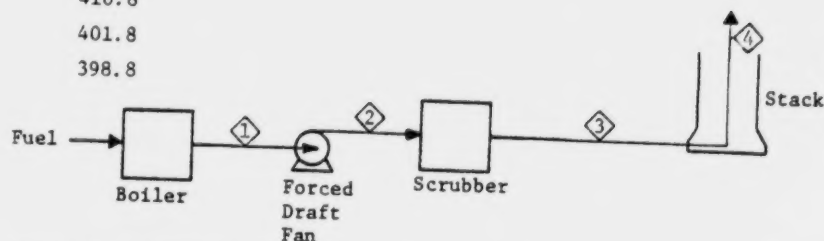
*includes a small amount of CO

Primary Fan Arrangement and Equipment Pressure Drop Assumptions

Equipment Pressure Drop	Impact of Fan Location on Flue Gas Composition and Adiabatic Saturation Temperature			
• Boiler ΔP = 22 in. H ₂ O	Fan Configuration	Forced Draft 34"ΔP (Figure 17a)	Forced Draft 40"ΔP (Figure 17b)	Induced Draft 40"ΔP (Figure 17c)
• Scrubber ΔP = 9 in. H ₂ O	Saturation Temperature (°F)	130	131	126
• Reheat Exchanger ΔP = 6 in. H ₂ O	Normalized Flue Gas Composition			
• Stack, Duct Work ΔP = 3 in. H ₂ O	Component	lbs/hr	lbs/hr	lbs/hr
	N ₂	3,471,000	3,471,000	3,471,000
	O ₂	259,700	259,700	259,700
	CO ₂	909,600	909,600	909,600
	H ₂ O	498,400	501,600	480,100
		5,139,000	5,142,000	5,120,000

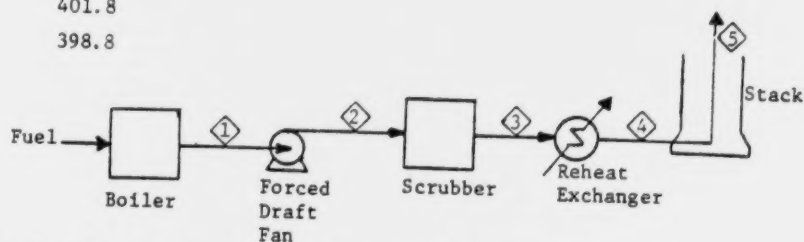
Note: The flue gas specific heat of each configuration was calculated to be 0.26 Btu/lb-°F.

	Temperature (°F)	Pressure (in. H ₂ O)
①	~300	376.8
②	~320	410.8
③	~130	401.8
④	~130	398.8



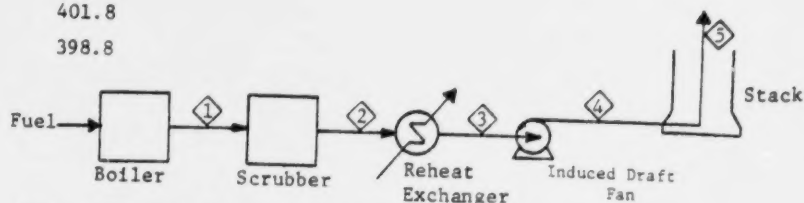
(a) Forced draft FGD system with no reheat (overall pressure drop = 34 in. H₂O)

	Temperature (°F)	Pressure (in. H ₂ O)
①	~300	376.8
②	~320	416.8
③	~131	407.8
④	~181	401.8
⑤	~181	398.8



(b) Forced draft FGD system with inline reheat (overall pressure drop = 40 in. H₂O)

	Temperature (°F)	Pressure (in. H ₂ O)
①	~300	376.8
②	~126	367.8
③	~156	361.8
④	~176	401.8
⑤	~176	398.8



(c) Induced draft FGD system with inline reheat (overall pressure drop = 40 in. H₂O)

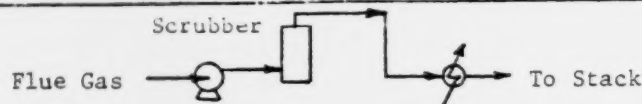
Figure 17. Schematics of different fan arrangements used to develop economics of various reheat configurations.

Reproduced from
best available copy.



TABLE 40. COST SUMMARY SHEET FOR INLINE REHEAT
(600 psia, dry saturated steam)

CONFIGURATION



Required Heat Input (10³Btu/hr) - 66.8
 Scrubbed Flue Gas:
 Temperature (°F) - 131
 Flow Rate (lbs/hr) - 5,140,000
 Reheat Steam:
 Temperature (°F) - 486
 Pressure (psia) - 600
 Flow Rate (lbs/hr) - 91,300

Stack Exit Temperature (°F) - 181
 Recirculation Exit Gas
 Temperature (°F) -
 Flow Rate (lbs/hr) -
 Reheat Air:
 Ambient Temperature (°F) -
 Heated Temperature (°F) -
 Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	8,100 (ft ²) ^a	\$ 20 (ft ²)	162,000
Exit Temp. (°F) - 181				
Exchanger LP (in. H ₂ O) - 6			31.5	
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan:	4		\$ 38,000 each	151,000
Size (HP) - 3240				
LP (in. H ₂ O) - 40				
Auxiliary Fan ^d :	-	- (HP)	\$ - each	-
LP (in. H ₂ O) - -				
Incremental Stack Cost ^e :	16		\$ 1,700 each	27,000
Soot Blowers:				
Total Equipment Cost ^f				340,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				198,000
Indirect Costs (4% of Total Equipment and Direct Labor & Material Costs)				242,000
TOTAL CAPITAL INVESTMENT				780,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost \$
Steam/Hot Water	91,300 (lbs/hr)	1.69 (\$/10 ³ lbs)	1,080,000
Electricity			
Primary Fan	1,460 (kw)	0.0314 (\$/kwh)	321,000
Auxiliary Fan	(kw)	(\$/kwh)	-
Maintenance and Replacement Cost			118,000
Depreciation			31,000
TOTAL ANNUAL OPERATING COST			1,550,000
ANNUAL REVENUE REQUIRED			1,624,000

^aArea shown is 10% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental

stack costs included in this total are installed costs.

the base case design (Figure 17a). An example is the increase in the capacity of the primary fan due to the increased system pressure drop that results from the addition of an inline reheat exchanger.

The results of estimating the costs associated with reheating flue gas with an inline reheater and various levels of saturated steam are summarized in Table 41 for an exchanger constructed with carbon steel tubes. The data in this table show that the exchanger surface area increases as the steam pressure decreases due to corresponding decreases in the temperature driving force. This increases the total capital investment as the steam pressure decreases from 600 psia to 16 psia. The operating costs, which are influenced by the quality of steam required for reheat, decrease as the steam pressure decreases from 600 psia to 83 psia; at 39 psia the operating costs begin to increase and reach their highest level at the lowest steam pressure, 16 psia. Comparison of the data in Table 41 shows that the most economical saturated steam level to use in a forced draft inline reheat configuration (with carbon steel tubes) may lie in the range of about 80 psia to 200 psia.* Based on these findings, it is expected that higher fuel (coal) costs will shift the optimum steam pressure downward. Also, higher exchanger costs (with stainless steel and Inconel 625 tubes) would tend to shift the optimum steam pressure upward.

Economic Sensitivity Studies for Inline Reheat Configurations--

Several sensitivity studies were conducted in order to determine how changes in various parameters would affect the costs of an inline reheater. For these studies a steam quality, fan arrangement, exchanger pressure drop, and tube material were selected as base case parameters. These parameters are:

*The economics developed in this study are based on many assumptions. With this in mind, the reheat costs for steam pressures greater than 16 psia are all fairly comparable.

TABLE 41. COSTS OF INLINE REHEAT USING VARIOUS DRY, SATURATED STEAMS

Dry, Saturated Steam Pressure (psia)	Steam Required (lbs/hr)	Exchanger Area (ft ²)	Total Capital Investment (\$10 ⁶)	Operating Cost (\$10 ⁶ /yr)	Annual Revenue Requirement (\$10 ⁶)
600	91,300	8,100	0.78	1.55	1.62
310	82,900	10,800	0.91	1.51	1.60
165	78,000	14,500	1.09	1.42	1.52
83	74,300	20,900	1.40	1.36	1.49
39	71,500	33,800	1.90	1.36	1.54
16	69,100	73,300	3.94	1.75	2.13
Hot Water (165)	534,000	23,000	1.50	1.57	1.71

Bases:

- (1) New 500-MW power plant described in Table 39.
- (2) Exchanger pressure drop equals 6 in. H₂O.
- (3) Flue gas is heated 50°F.
- (4) Mist carryover from the scrubber and duct and stack heat losses are considered negligible.
- (5) 66.8 x 10⁶ Btu/hr heat input in the reheater.
- (6) Bases for exchanger sizing given in Appendix E.

Steam Pressure: 165 psia, dry, saturated steam

Primary Fan Arrangement: Forced draft

Exchanger Characteristics: (a) pressure drop - 6 in. H₂O
(b) tube material - carbon steel
(c) tube life - 2 years

Annual Revenue Requirement (ARR): $\$1.52 \times 10^6/\text{yr}$

The results of the sensitivity studies conducted for the inline reheat configuration are summarized in Table 42. Also, presented in this table is a comparison of the annual revenue requirement for each case with that of the base case. The bases and results of the sensitivity studies are described below:

Case A - The tube material is changed from carbon steel (in the base case exchanger) to 316L stainless steel in this case. It was estimated that the use of 316L SS would increase the tube life from 2 years (base case) to 4 years based on information obtained from the reheat survey (Section 5). The ARR increased by about 2 percent compared to the base case ARR. The ARR increase is the result of the substantial increase in capital requirement resulting from the use of stainless steel tubes.

Case B - In this case, the exchanger tube material is Inconel 625. Based on heat exchanger vendor information, it was estimated that the use of Inconel 625 would increase tube life to about eight years. This very expensive alloy results in the ARR being about 6 percent higher than the base case ARR.

Case C - In this case, the exchanger pressure drop is designed as 3 in. H₂O. It was anticipated that the lower pressure drop would increase the surface area requirements of the exchanger. Consequently, increased capital costs and decreased operating costs were expected for Case C compared with the base case.

The results of this analysis show that the design of an exchanger with a 3 in. H₂O pressure drop results in an 8 percent lower ARR requirement compared to the base case ARR. Although the lower pressure drop slightly increases the exchanger surface area and capital costs, the savings in operating costs due to the decreased primary fan energy requirement is the overriding factor.

TABLE 42. SUMMARY AND COMPARISON OF ECONOMICS FOR INLINE REHEAT (SENSITIVITY ANALYSES)

Cases Studied	Reheat Steam Quality	Primary Fan Position	Stack Exit Temperature (°F)	Exchanger Pressure Drop (in. H ₂ O)	Tube Life (years)	Total Capital Investment (10 ⁶ \$)	Operating Cost (10 ⁶ \$/yr)	Annual Revenue Requirement (10 ⁶ \$)	Impact on Base Case ARR ^a %	
									Increase	Decrease
Base Case	165 psia, dry, saturated	forced draft	181	6	2	1.09	1.42	1.52	base case	
Sensitivities										
• Case A ^b	165 psia, dry, saturated	forced draft	181	6	4	1.49	1.41	1.55	2	
• Case B ^c	165 psia, dry, saturated	forced draft	181	6	8	2.14	1.41	1.62	6	
• Case C	165 psia, dry, saturated	forced draft	181	3	2	1.13	1.29	1.40	8	
• Case D	165 psia, superheated	forced draft	181	6	2	1.05	1.40	1.50	1	
• Case E	165 psia, dry, saturated	induced draft	176	3	2	0.51	0.55	0.59	61	
• Case F	165 psia, dry, saturated	induced draft	197	6	2	0.90	1.11	1.19	22	
• Case G	165 psia, dry, saturated	forced draft	181	6	1	1.09	1.60	1.70	12	

^aAnnual revenue requirement^bExchanger tubes constructed of 316L stainless steel; tube life assumed to be 4 years.^cExchanger tubes constructed of Inconel 625; tube life assumed to be 8 years.

Bases:

(1) Flue gas is nominally reheated by 50°F. Mist carryover and heat losses are assumed to be negligible.

(2) Tube material and tube life in base case exchanger are carbon steel and 2 years, respectively.

(3) New 500-t/M power plant described in Table 39.

(4) Bases for total capital investment, operating cost, and annual revenue requirement given in Appendix C.

(5) 1978\$

Case D - Superheated steam (165 psia, 745°F) is utilized as reheat steam in Case D. As expected, the use of superheated steam reduces the capital requirement; however, the overall benefit achieved by using superheated steam instead of saturated steam is marginal (approximately a one percent decrease in the base case annual revenue requirement).

Case E - In this case, the fan is repositioned to follow the scrubber and reheater (induced draft). The pressure drop in the exchanger is 3 in. H₂O. The induced draft fan increases the flue gas temperature by about 20°F due to the work of compression; consequently, the reheater need supply only about 30°F of heat input compared to the 50°F input required with the forced draft primary fan configuration. A schematic of an inline reheater being utilized with an induced draft fan is presented in Figure 17 C.

This case shows the benefit to be gained by using the work of compression of an induced draft primary fan to supply a portion of the desired reheat.

Case F - Some users of inline reheaters who responded to the OMB-approved questionnaire indicated that 50°F of reheat should be added to the flue gas prior to its entering an induced draft fan in order to protect the fan against corrosion. Consequently, this case involves the use of the same configuration as Case E (Figure 17C). However, the reheater supplies 50°F of reheat; while the fan adds another 20°F due to the work of compression. Thus, the resulting reheater gas exit temperature is 70°F greater than the scrubber exit temperature.

Although this case exhibits the poorest economics of the induced draft cases studied, it is still economically attractive compared to the forced draft primary fan cases evaluated.

Case G - In this case, the base case tube life is changed from 2 years to 1 year to illustrate the sensitivity of the economics to a change in tube life without a change in tube material.

The cost summary sheets developed for these cases are presented in Tables E-8 through E-14 in Appendix E.

The economics (capital requirements and operating costs) for inline reheat systems (with different exchanger tube materials) are summarized in Table 43. The data show that both the capital investment and ARR increase when higher priced alloys are used.

Summary--

Based on the various studies conducted for inline reheat, the following are concluded:

- (1) The use of more expensive alloys such as 316L SS and Inconel 625 will substantially increase the capital requirement of an inline system. The annual revenue requirement is affected to a lesser degree, however, since longer tube life is expected. Reheat users should consider using expensive alloys in the front of the exchanger and less expensive materials (corten or carbon steel) at the rear of the exchanger.
- (2) The annualized cost of an inline reheat is highly dependent on tube life. Therefore, factors that would influence tube life (mist eliminator performance, soot blowing, tube material) are important parameters to be considered in designing an inline reheat system.
- (3) For the bases used in this study, the lowest costs for reheating a flue gas with an inline reheater were attained with the use of medium pressure steam.
- (4) The advantage of using a superheated instead of a dry, saturated steam of the same pressure appears to be marginal.
- (5) The use of an induced draft primary fan to supply a portion of the desired reheat has significant economic advantages over a forced draft arrangement. However, the viability of this concept is dependent on protection of the fan from corrosion.
- (6) An optimum exchanger pressure drop (gas-side) appears to be closer to 3 in. H₂O than 6 in. H₂O.

Economics of the Indirect Hot Air Reheat Configuration

Two heat input bases were used to estimate the costs of utilizing the indirect hot air configuration. In the first basis, it is assumed that

TABLE 4.3. EVALUATION OF EXCHANGER TUBE METALLURGY FOR INLINE REHEAT (1978 \$)

Reheat Exchanger Tube Material	Carbon Steel			Stainless Steel 316L			Inconel 625	
	Capital Requirement (10 ⁶ \$)	Annual Revenue Requirement (10 ⁶ \$/yr)	Capital Requirement (10 ⁶ \$)	Annual Revenue Requirement (10 ⁶ \$/yr)	Capital Requirement (10 ⁶ \$)	Annual Revenue Requirement (10 ⁶ \$/yr)	Capital Requirement (10 ⁶ \$)	Annual Revenue Requirement (10 ⁶ \$/yr)
Dry, Saturated Steam Pressure (psia)								
16	1.9	2.1	-*	-	-	-	-	-
39	1.9	1.5	-	-	-	-	4.6	1.8
83	1.6	1.5	-	-	-	-	2.9	1.6
165	1.1	1.5	1.5	1.6	-	-	2.1	1.6
310	0.9	1.6	-	-	-	-	1.9	1.7
600	0.8	1.6	-	-	-	-	1.4	1.7

*Means that the economies were not estimated for that case

Reheat Exchanger Bases:

- (1) See Table 1B for exchanger sizing and cost development.
- (2) Forced draft primary fan arrangement (see Figure 17a).
- (3) Exchanger $\Delta P = 6$ in. H₂O.
- (4) Flue gas is reheated 50°F.

the quantity of heat added to the ambient air before it was mixed with the wet flue gas is equivalent to the heat added to the flue gas by an inline reheater supplying 50°F of reheat. This basis reflects the results developed in Section 6 which show that the heat required to prevent visible plume formation is approximately the same for the inline and indirect hot air configurations. It was also shown in Section 6 that the two configurations have comparable impacts on ground-level pollutant concentrations when equivalent heat inputs are used. For a 500-MW power plant, a heat input (to the flue gas) of 66.8×10^6 Btu/hr* is required to provide 50°F of reheat with an inline reheater. Depending on the steam level used for reheat, the use of the indirect hot air configuration to input 66.8×10^6 Btu/hr resulted in the flue gas-heated air mixture having a stack exit temperature that varied from 133-165°F. This temperature range reflects the different hot air temperatures and flow rates that result from the use of the various steam levels.

The second basis reflected the response obtained from reheat users indicating that an approximate 50°F increase in the stack exit temperature of the scrubbed flue gas-heated air mixture was needed to protect downstream equipment. Based on this information, the stack exit temperature was defined to be 50°F hotter than the scrubber exit temperature. Achieving this temperature rise in a forced draft primary fan arrangement resulted in a 180°F stack exit temperature.

Initially, only dry, saturated steam levels and a forced draft primary fan arrangement were considered during the sizing and subsequent cost estimation of the indirect hot air configuration. Since each steam level had a different condensing temperature, several air approach temperatures (temperature difference between the temperatures of the entering steam and the exiting air) were evaluated for the different steam levels. A simplified schematic of a forced draft primary fan, indirect hot air reheat configuration is presented in Figure 18. An example cost summary sheet which shows

*See bases on page 137.

the capital and operating costs that must be considered for this configuration is presented in Table 44. As this table shows, the capital investment for this configuration not only includes the costs of the exchanger and auxiliary air fan, but also includes an incremental stack cost. Since indirect hot air reheat increases the mass flow rate of the flue gas, the incremental stack cost reflects an increase in the base case stack size in order to keep the stack velocity constant. It was assumed that no soot blowers were needed for this configuration because the air being heated is considerably cleaner than flue gas. Cost summary sheets for cases based on both the assumed 180°F stack exit temperature and the assumed heat input of 66.8×10^6 Btu/hr are presented in Tables E-15 through E-25 in Appendix E.

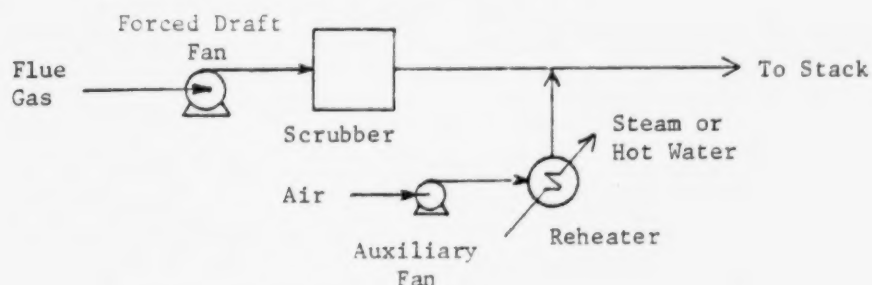
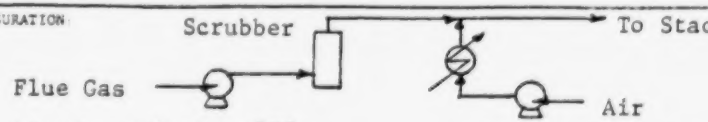


Figure 18. Simplified schematic of indirect hot air reheat configuration with a forced draft primary fan arrangement.

The costs developed for the indirect hot air configurations are presented in Table 45. This table shows that for the same steam pressure and air approach temperature, the costs of those cases in which a heat input of 66.8×10^6 Btu/hr was specified are significantly less than the costs of those cases in which a 180°F stack exit temperature is required. However, the maximum stack exit temperature attained in any case for the heat input of 66.8×10^6 Btu/hr is 165°F and a minimum stack exit temperature of 133°F is attained when 16 psia, dry, saturated steam is used as the heating medium. Since many reheat users indicate that (1) equipment protection is the

TABLE 44. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(600 psia, dry saturated steam, air approach
temperature = 80°F, $\Delta T_{\text{flue gas}} = 50^\circ\text{F}$)

CONFIGURATION	
	
Required Heat Input (10 ³ Btu/hr) - 102	Stack Exit Temperature (°F) - 180
Scrubbed Flue Gas:	Recirculation Exit Gas:
Temperature (°F) - 130	Temperature (°F) -
Flow Rate (lbs/hr) - 5,140,000	Flow Rate (lbs/hr) -
Reheat Steam:	Reheat Air:
Temperature (°F) - 486	Ambient Temperature (°F) - 60
Pressure (psia) - 600	Heated Temperature (°F) - 406
Flow Rate (lbs/hr) - 138,000	Flow Rate (lbs/hr) - 1,180,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	21,500 (ft ²) ^a	\$ 11 / ft ²	237,000
Exit Temp. (°F) - 406				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b - 26.2				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) - 9.3	4	114 (HP)	\$22,800 each	91,000
Incremental Stack Cost ^e :				
Stack Cost ^f	-		\$ - each	286,000
Soot Blowers:				
Total Equipment Cost ^g				- 614,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				- 378,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				- 406,000
TOTAL CAPITAL INVESTMENT				1,398,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	138,000 (lbs/hr)	1.69 (\$/10 ³ lbs)	1,632,000
Electricity			
Primary Fan	(kw)	(\$/kwh)	
Auxiliary Fan	340 (kw)	0.0314 (\$/kwh)	75,000
Maintenance and Replacement Cost			40,000
Depreciation			56,000
TOTAL ANNUAL OPERATING COST			1,803,000
ANNUAL REVENUE REQUIRED			1.94 x 10 ⁵

- ^aArea shown is 10% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE 45. ECONOMICS OF USING DRY, SATURATED STEAM IN INDIRECT HOT AIR REHEAT SYSTEMS

Bases For Studies	Steam Pressure (psia)	Air Approach ^a Temperature (°F)	Required Heat Input (10 ⁶ Btu/hr)	Stack Exit Temperature (°F)	Steam Required (10 ³ lbs./hr)	Exchanger ^b Area (ft ²)	Capital Cost (10 ³ \$)	Annual Operating Costs (10 ³ \$/yr)	Annual Revenue Required (10 ³ \$)
180°F Stack Exit ^c Temperature									
	600	80	102	180	138	21,500	1.40	1.80	1.94
	310	80	117	180	143	27,500	1.83	1.96	2.14
	165	40	122	180	140	43,900	2.47	1.85	2.06
	165	80	142	180	164	35,300	2.40	2.12	2.35
	165	120	188	180	216	35,500	2.90	2.81	3.09
66.8 × 10 ⁶ Btu/hr Heat Input ^d									
	600	80	66.8	165	90	14,100	0.97	1.19	1.28
	310	80	66.8	162	82	15,700	1.09	1.13	1.23
	165	40	66.8	161	77	24,100	1.40	1.01	1.14
	165	80	66.8	158	77	16,600	1.20	1.00	1.11
	165	120	66.8	155	77	12,600	1.14	1.01	1.12
	16	80	66.8	133	67	19,900	1.98	0.72	0.90

^aThis temperature represents the approach of the air temperature leaving the reheater to the entering temperature of the steam. Area shown includes a 10 percent safety factor.

^bReflects survey responses which indicate that the stack exit temperature is typically heated to a level about 50°F above the scrubber exit temperature in order to protect downstream equipment from corrosion.

^cEquivalent to reheating a flue gas (with an inline reheater) by 50°F assuming no mist entrainment and no stack or duct work heat loss.

^dBases:

- (1) New 500-MW power plant
- (2) No mist entrainment or heat losses occur downstream of the mist eliminator.
- (3) Forced draft primary fan configuration
- (4) Exchanger pressure drop = 6 in. H₂O
- (5) Ten year tube life

primary reason for the use of reheat and (2) a 50°F increase in the stack temperature is required to adequately protect downstream equipment, it is likely that most indirect hot air reheat systems will be designed based on a specified stack exit temperature rather than a specified heat input to the gas.

A comparison of the cases presented in Table 45 which are based on a 180°F stack exit temperature shows that the lowest costs correspond to the 600 psia, dry, saturated steam case. This indicates that the higher cost for high pressure steam is more than offset by lower exchanger surface area and energy requirements compared to the low pressure steam cases.

Sensitivity Studies for the Indirect Hot Air Reheat Configuration--

During the saturated steam studies, several parameters which could have a significant impact on the indirect hot air reheat configuration were identified. In order to quantify their impact, an indirect hot air reheat case was selected as the base case for a design parameter sensitivity study. This base case is defined below.

Reheat Level: Based on the stack exit temperature being 50°F greater than scrubber exit

Reheat Conditions: Dry, saturated, 165 psia steam

Fan Configuration: Forced draft primary fan (see Figure 18)

Exchanger Characteristics: (a) pressure drop = 6 in. H₂O
(b) carbon steel tubes
(c) tube life = 10 years
(d) air approach temperature = 80°F

Annual Revenue Requirement: $\$2.35 \times 10^6$

The results of the indirect hot air reheat sensitivity studies are presented in Table 46. The bases and results of these sensitivity studies are discussed below:

TABLE 46. SUMMARY AND COMPARISON OF ECONOMICS DEVELOPED FOR INDIRECT HOT AIR REHEAT SENSITIVITY STUDIES

Bases for Studies	Steam Quality	Fan Position	Stack Exit Temperature (°F)	Exchanger Pressure Drop (in. H ₂ O)	Air Approach Temperature (°F)	Heat Input Required (Btu/hr)	Capital Investment (10 ⁵ \$)	Annual Operating Costs (10 ⁵ \$/yr)	Annual Revenue Required (10 ⁵ \$/yr)	Impact on Base Case ARR	
										% Increase	% Decrease
Base Case	165 psia, dry, saturated	forced draft	180	6	80	142 x 10 ⁶	2.40	2.12	2.35	base case	
Sensitivity Studies	• Case A	165 psia, dry, saturated	180	12	80	142 x 10 ⁶	2.29	2.19	2.41	3	
	• Case B	165 psia, 745°F, superheated	180	6	80 (in condenser)	117 x 10 ⁶	1.94	1.70	1.89	20	
	• Case C	165 psia, dry, saturated	175	30	80	109 x 10 ⁶	1.10	1.30	1.41	40	
	• Case D	600 psia, dry, saturated	193	30	40	120 x 10 ⁶	1.07	1.78	1.89	20	
	• Case E	600 psia, 639°F, superheated	176	30	40 (in condenser)	81 x 10 ⁶	0.61	0.82	0.88	63	

Bases:

(1) New 500-MW power plant

(2) 50°F of reheat

(3) No heat loss downstream of the scrubber and no mist entrainment occur.

Case A - In this case the exchanger pressure drop is increased from 6 to 12 in. H₂O. As expected, operating costs increase and capital costs decrease compared to the base case. The resulting ARR is about 3 percent higher than the base case ARR.

Case B - For this case 165 psia, superheated steam is used as the heating medium. It was expected that use of this steam level would decrease the energy requirements because less air would be needed to reheat the flue gas. The resulting ARR is about 20 percent lower than the base case ARR.

Case C - In this case, the primary fan in the base case was repositioned to follow both the scrubber and the hot air-flue gas mixing point. This induced draft primary fan arrangement raises the temperature of the flue gas-air mixture by about 20°F due to the work of compression. Consequently, the exchanger for this case is sized to supply enough heat so the hot air raises the scrubbed flue gas temperature by 30°F after mixing. A simplified schematic of this configuration is presented in Figure 19. The resulting annual revenue requirement is about 40 percent lower than the base case ARR.

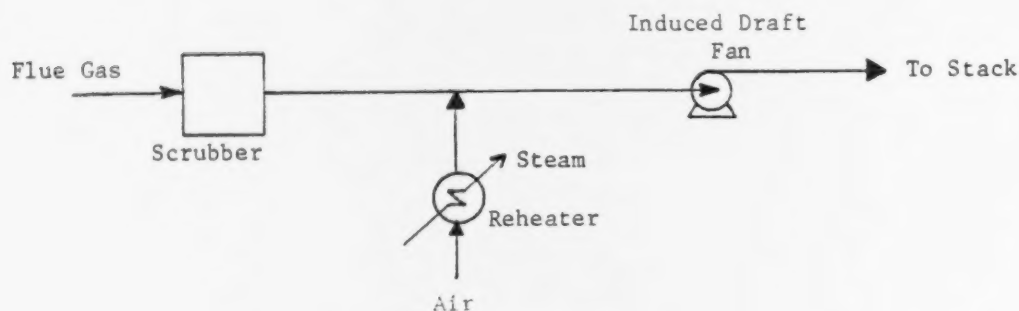


Figure 19. Simplified schematic of indirect hot air reheat configuration with an induced draft primary fan.

Case D - Several of the base case parameters were changed:

- (1) 600 psia, dry, saturated steam as the reheat media
- (2) An induced draft primary fan configuration (Figure 19)
- (3) A 40°F air approach temperature

The air heater in this case is sized to supply enough heat to raise the temperature of the flue gas-air mixture by 50°F. Users of reheat have indicated that heating

the flue gas to this temperature will protect the fan from corrosion. Since the work of compression (from the primary fan) will raise the flue gas-injected air temperature by about 18°F, the actual stack gas exit temperature is 68°F above the scrubber exit temperature. The annual revenue requirement is about 20 percent less than the base case ARR.

Case E - The induced draft primary fan arrangement (see Figure 19) is utilized. The steam level used in this case is 600 psia, 639°F superheated steam. The stack gas exit temperature is 50°F above the scrubber exit temperature. Since the work of compression contributes approximately 20°F, the air heater is sized to supply 30°F of reheat. The annual revenue requirement is about 63 percent less than the base case ARR.

The cost summary sheets developed for the different cases defined above are presented in Tables E-26 through E-30 in Appendix E.

Summary--

Assuming a stack exit temperature that is 50°F higher than the scrubber exit temperature, it is concluded that:

- (1) Indirect hot air reheat is generally more expensive than inline reheat. This is because the indirect hot air reheat configuration requires substantially more energy than inline reheat due to the greater mass of gas (total gas made up of flue gas and air) that must be heated to the stack exit temperature.
- (2) The indirect hot air reheat user has strong economic incentives to minimize the air injected into the flue gas since excess reheat energy is required for the air. Therefore high injected air temperatures (exiting the reheater) are advantageous. This means that high grade steam (high pressure with superheat) and close approach temperatures in the exchanger offer advantages.
- (3) There are significant economic advantages associated with the use of an induced draft primary fan configuration because it can supply a portion of the flue gas reheat due to the work of compression. However, the viability of this configuration is dependent on the flue gas entering the fan being hot enough to protect the primary fan from corrosion and deposition of solids.

Economics of Exit Gas Recirculation (EGR) Reheat

Although exit gas recirculation has not been commercially proven, the capital and operating costs of using various levels of saturated steam with this configuration were estimated. The size and cost of the reheat exchanger in this configuration are expected to be very dependent on the approach temperature in the reheat exchanger.* Consequently, several approach temperatures were considered for each steam level. In each case, a forced draft primary fan configuration (see Figure 20) and 50°F increase** in the stack gas temperature is the basis for the reheater design. An example cost summary sheet for this reheat system is presented in Table 47. The cost summary sheets developed for cases analyzed in this study are presented in Tables E-31 through E-35 in Appendix E. The results of this study are summarized in Table 48. The data presented in this table show that exit gas recirculation may be economically attractive compared to inline reheat.

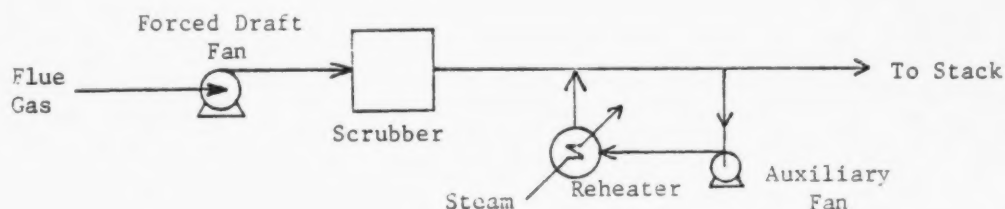


Figure 20. Simplified schematic of exit gas recirculation configuration with a forced draft primary fan arrangement.

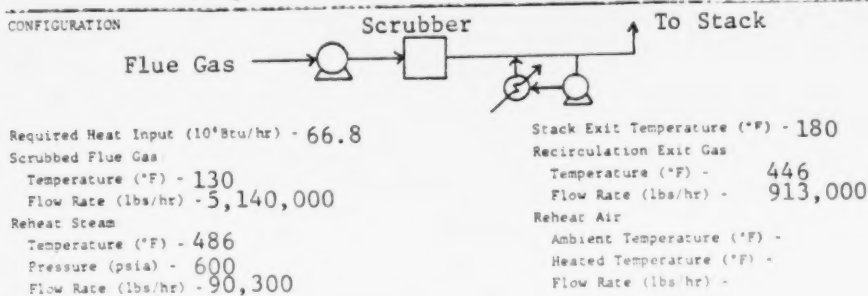
Exit Gas Recirculation Sensitivity Studies--

The base case conditions selected for evaluating the economic sensitivity of exit gas recirculation to various design parameters are as follows:

*Approach temperature is defined as the temperature of steam entering the reheat exchanger minus the temperature of the heated gas leaving the exchanger.

**Mist carryover and heat losses downstream of the mist eliminator were assumed negligible.

TABLE 47. COST SUMMARY SHEET FOR EXIT GAS RECIRCULATION
(600 psia, dry saturated steam; flue gas approach
temperature = 40°F)



EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger	4	37,700 (ft ²) ^a	\$ 20 /ft ²	754,000
Exit Temp (°F) - 446				
Exchanger SP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			16.9	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -			-	
Primary Fan				
Size (HP) - 2755	4		\$ - each	-
SP (in. H ₂ O) - 34				
Auxiliary Fan ^d				
SP (in. H ₂ O) - 6	4	70 (HP)	\$ 17,500 each	70,000
Incremental Stack Cost ^e	8		\$ 1,700 each	14,000
Soot Blowers				
Total Equipment Cost ^f				838,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				595,000
Indirect Costs (+5% of Total Equipment and Direct Labor & Material Costs)				645,000
TOTAL CAPITAL INVESTMENT				2,078,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	90,300 (lbs/hr)	1.69 (\$/10 ³ lbs)	1,068,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	208 (kw)	0.0314 (\$/kwh)	46,000
Maintenance and Replacement Cost			231,000
Depreciation			83,000
TOTAL ANNUAL OPERATING COST			1,428,000
ANNUAL REVENUE REQUIRED			1.63 x 10 ⁶

^aArea shown is 25% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE 48. COST OF USING DRY, SATURATED STEAM TO REHEAT FLUE GAS WITH AN EXIT GAS RECIRCULATION SYSTEM

Saturated Steam Pressure (psia)	Approach Temperature ^a (°F)	Reheat Exchanger Gas Side Pressure Drop (in. H ₂ O)	Exchanger Area (ft ²)	Capital Requirement (10 ⁶ \$)	Operating Cost (10 ⁶ \$/yr)	Annual Revenue Requirement (10 ⁶ \$/yr)
600	40	6	37,700	2.08	1.43	1.63
600	80	6	26,200	1.53	1.35	1.49
310	120	6	21,100	1.31	1.27	1.40
165	80	6	31,300	1.82	1.22	1.39
165	120	6	21,000	1.37	1.21	1.34

^aSteam inlet (to reheat exchanger) temperature minus flue gas temperature exiting the reheat exchanger.

Bases:

- (1) New 500-MW power plant with 50°F of flue gas reheat after the scrubber.
- (2) No entrainment present or heat losses occur downstream of the mist eliminator.
- (3) 180°F stack exit temperature.
- (4) Forced draft primary fan arrangement.
- (5) Tube life assumed to be 4 years.

Steam Level: 165 psia, dry, saturated
 Approach Temperature: 80°F
 Exchanger Pressure Drop: 6 in. H₂O
 Primary Fan Configuration: Forced draft (Figure 20)
 Annual Revenue Requirement: $\$1.39 \times 10^6$

The results of the sensitivity analysis are summarized in Table 49. The bases and results for the sensitivity studies conducted are:

Case A - A 165 psia, 745°F superheated steam is used as the reheat medium. An 80°F approach temperature and a 6 in. H₂O pressure drop is also incorporated into the design. The resulting ARR is about 1 percent lower than the base case ARR. Therefore, the use of superheated steam appears to offer no significant advantage over saturated steam in EGR systems.

Case B - An induced draft primary fan configuration is evaluated in this case. An auxiliary fan is also required. A simplified schematic of the induced draft arrangement is presented in Figure 21. The resulting ARR is about 56 percent lower than the base case ARR.

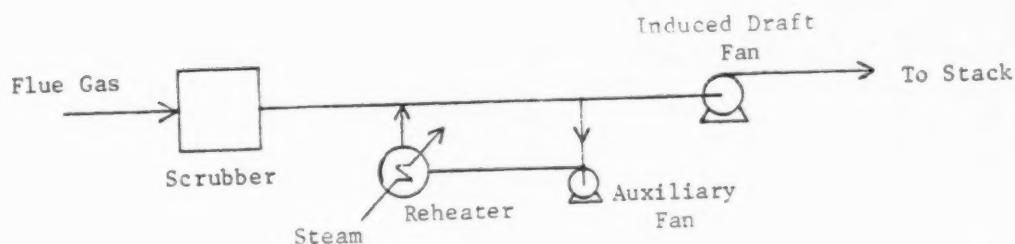


Figure 21. Simplified schematic of exit gas recirculation reheat with an induced draft primary fan arrangement.

Case C - An induced draft primary fan arrangement (Figure 22) is the last case evaluated. A small exchanger is used to reheat the recirculated gas enough to protect the fan. In this case the heat due to the work of compression supplies a portion of the desired reheat, while a larger exchanger which follows the fan supplies the remainder of the reheat needed. The resulting ARR is about

TABLE 49. ECONOMICS FOR EXIT GAS RECIRCULATION SENSITIVITY STUDIES

Cases Studied	Steam Quality	Approach Temperature (°F)	Primary Fan Position	Reheat Exchanger ΔP (in. H ₂ O)	Exchanger ^a Area (ft ²)	Capital Investment (10 ⁵ \$)	Annual Operating Costs (10 ⁵ \$)	Annual Revenue Required (10 ⁵ \$)	Impact on Base Case % Increase	base case
Base Case	165 psia, dry, saturated	80	forced draft	6	31,300	1.82	1.22	1.39		
Sensitivity * Case A	165 psia, 745°F, superheat	80	forced draft	6	30,900	1.79	1.20	1.37		1
* Case B	165 psia, dry, saturated	80	induced draft	6	19,700	1.02	0.52	0.61		56
* Case C	165 psia, dry, saturated	80	induced draft	30(auxiliary) 3(primary)	3,300 5,700	0.46	0.51	0.56		60

^aExchanger area 25 percent greater than actually calculated.

Bases:

(1) New 500-MW power plant.

(2) No heat losses or mist entrainment occur downstream of the mist eliminator.

(3) 180°F stack exit temperature

60 percent lower than the base case annual revenue requirement. In this case, however, the fan may not be adequately protected against corrosion.

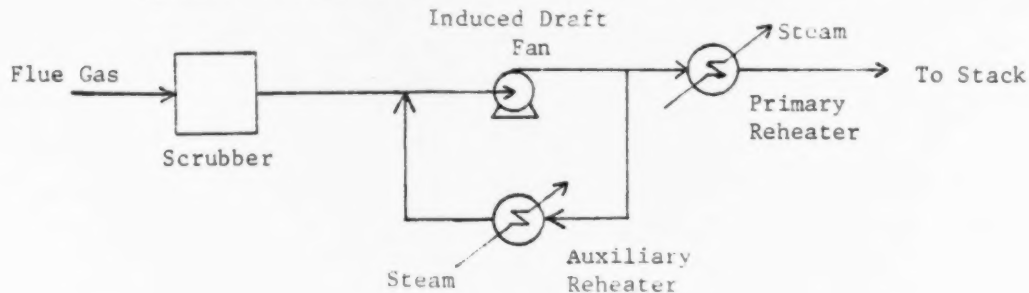


Figure 22. Simplified schematic of an advanced EGR reheat configuration.

Summary--

From the cases developed for exit gas recirculation reheat, it is concluded that:

- (1) EGR, although unproven commercially, appears to be economically attractive compared to inline and indirect hot air reheat systems.
- (2) Superheated steam appears to offer no significant economic advantage over saturated steam as the reheat medium.
- (3) There are significant economic advantages associated with the use of an induced draft primary fan configuration because it can supply a portion of the flue gas reheat due to the work of compression. However, the viability of this configuration is dependent on the flue gas entering the fan at a high enough temperature for protection against corrosion.

Economics of Direct Combustion

The costs of reheating a flue gas with a direct combustion reheat system are also estimated. The equipment costs for a fuel oil-fired direct combustion reheat system are based on a 500-MW power plant and were obtained from the literature.^{29,30} These costs are presented in Table 50 for both forced and induced draft primary fan configurations. Schematics of these configurations are presented in Figure 23.

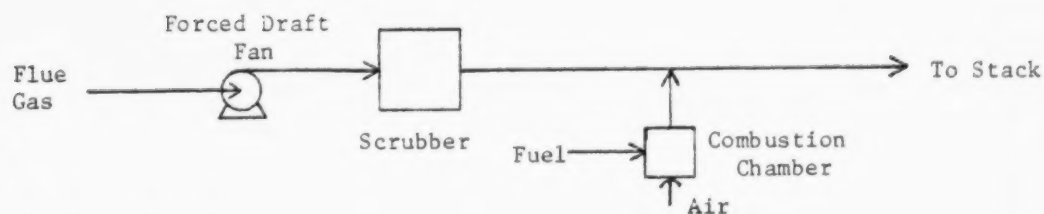
TABLE 50. COSTS OF DIRECT COMBUSTION REHEAT (1978 \$)

	Primary Fan Configuration	
	Forced Draft	Induced Draft
<u>Capital Requirement</u>		
Oil Storage Tank (1 required)*	\$ 95,000	\$ 70,000
Burner Packages (4 required)	292,000	215,000
Primary Fan Credit		<11,000>
Total Equipment Cost	387,000	274,000
Direct Labor and Materials (Installation)	155,000	110,000
Indirect Costs	244,000	173,000
TOTAL CAPITAL INVESTMENT	\$ 786,000	\$557,000
<u>Operating Costs</u>		
Fuel (\$3.00/10 ⁶ Btu)	1,403,000	841,000
Electricity Credit		<167,000>
Maintenance, 8%	43,000	31,000
Depreciation	31,000	22,000
ANNUAL OPERATING COST	1,477,000	727,000
ANNUAL REVENUE REQUIREMENT	\$1,552,000	780,000

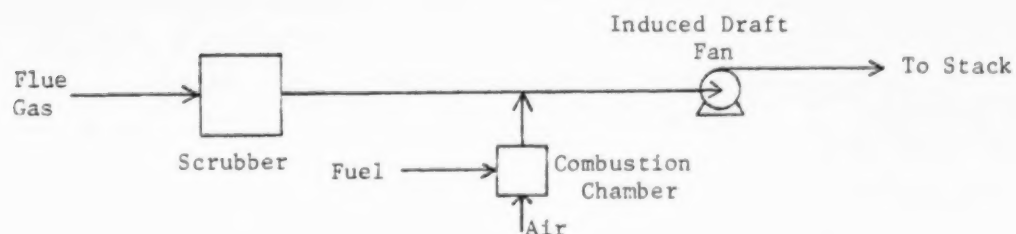
*Approximately 30-day capacity.

Bases:

- (1) Stack exit temperature is 50°F higher than scrubber exit temperature.
- (2) For induced draft case, it was assumed that 20°F of desired reheat was obtained from work of compression; consequently, reheat system was designed to supply 30°F of reheat.
- (3) Economics reflect firing of No. 2 fuel oil.



(a) forced draft primary fan configuration



(b) induced draft configuration

Figure 23. Schematics of direct combustion reheat configurations with forced and induced draft primary fan arrangements.

As expected, the direct combustion reheat configuration with an induced draft primary fan is considerably less expensive than the forced draft fan arrangement. This is due to (1) the lower fuel consumption exhibited by the induced draft fan arrangement, and (2) the smaller sized fan which is needed for the induced draft system (the smaller fan requirements result in credit for both the capital and operating costs).

The costs in Table 50 show that the annual revenue requirements of a direct combustion (fuel oil firing) reheat scheme are competitive with the other reheat configurations.^{*} However, over the life of the process the

^{*}For the fuel costs specified. No. 2 fuel oil costs are currently much higher than the \$3/10⁶ Btu used in this example.

revenue requirements of the direct combustion system are expected to rise faster than those of the inline, indirect hot air, and EGR reheat configurations because a higher fraction of this configuration's revenue requirements is attributable to fuel costs.

A direct combustion reheat system firing natural gas would exhibit the following characteristics.* The capital requirement would be somewhat lower since a fuel oil tank would not be required. Although the burner packages (including the combustion chamber) would differ somewhat, the capital investment is expected to be similar. Since the major component of the annual revenue requirement for a direct combustion system is related to the fuel costs, small differences in the capital requirements will not have a significant impact on the relative ARR's of the two systems. The economic viability of a natural gas versus fuel oil system will depend primarily on the relative delivered costs (on a $\$/10^6$ Btu basis) of the fuels.

Retrofit Reheat Systems

The economic assessment of the costs of retrofitting reheat to an existing boiler-FGD system is very site specific. The items that are expected to cause uncertainties are:

- (1) Capability of existing primary fan to handle higher flow rates and/or pressure drops.
- (2) Capability of the existing turbine to supply reheat steam and the resulting energy or power generation penalties.
- (3) Space for installing the reheat system.

The direct combustion case economics developed for new plants are a good approximation of retrofit costs for this reheat system. The inline, EGR, and indirect hot air reheat system economics for retrofit applications are too site specific and are not attempted in this report.

*Compared to a direct combustion system firing oil.

COMPARISON OF REHEAT SYSTEM ECONOMICS

The economics of the four reheat systems for new 500-MW power plants are analyzed and compared below.

Evaluation of Reheat System Costs and Comparison to FGD System and Power Plant Costs

Capital investment and operating costs for SGR systems will vary considerably depending on the following parameters:

- (1) Steam quality (temperature, pressure) and availability
- (2) Fuel cost (\$/10⁶ Btu for coal, fuel oil, natural gas, steam)
- (3) Type of reheat system selected (EGR, inline, indirect hot air, direct combustion)
- (4) Exchanger design criteria
- (5) Reheat temperature desired
- (6) Reheat exchanger metallurgy
- (7) New or retrofit installation

Ranges of costs for selected reheat cases are presented in Table 51. The costs are compared to costs for a new coal-fired plant and a limestone FGD system. It should be emphasized that the reheat costs shown are not for optimized designs. The inline, indirect hot air, and exit gas recirculation ranges are based on the use of dry, saturated steam (165-600 psia) as the reheat medium. This basis penalizes the indirect hot air injection system since the use of superheated steam is very attractive for indirect hot air but only marginally attractive for inline and EGR reheat. In addition, other reheat exchanger parameters, such as gas-side pressure drop, exchanger approach temperature, tube spacing, and use of finned tubes for hot air injection, have not been optimized. Finally, the cost of reheater downtime

TABLE 51. STACK GAS REHEAT ECONOMIC EVALUATION SUMMARY (1978 \$)

	Reheat System		
	Indirect Hot Air	Exhaust Gas Recirculation (EGR)	Direct Combustion
Reheat System Capital Requirement, 10 ⁶ \$	0.8 - 2.9 ^c	1.3 - 2.1	0.8
% of FGD System ^a Capital Requirement	1.1 - 3.6	1.7 - 2.8	1.1
% of Total Power Plant ^b Capital Requirement	0.2 - 0.7	0.3 - 0.5	0.2
Reheat System Annual Revenue Requirement (ARR), 10 ⁶ \$/year	1.5 - 1.7	1.4 - 1.6	1.6 - 2.0
% of FGD System ^a ARR	7.1 - 8.1	6.7 - 7.6	7.6 - 9.5
% of Total Power Plant ^b ARR	1.4 - 1.5	1.3 - 1.5	1.5 - 1.8
Notes			
Stream Quality	Dry, Saturated (165-600 psia)	Dry, Saturated (165-600 psia)	-
Tube Metallurgy ^c	Carbon Steel, 316 SS Inconel 625	Carbon Steel	-
Fuel Costs	Based on coal in new power plant at \$1/10 ⁶ Btu	Based on coal in new power plant at \$1/10 ⁶ Btu	\$3-4/10 ⁶ Btu 80% 2 fuel oil

^aFGD system costs are taken as \$150/kw (capital requirement) and 6 milts/wh (annual revenue requirement).

^bA new power plant (including FGD system) costs are taken as \$800/kw (capital requirement) and 31.4 milts/wh (annual revenue requirement). See Appendix E.

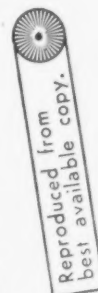
^cFor inline reheat the large range for capital requirement is due primarily to the estimation of capital investments for several different tube materials.

Notes: (1) 50°F of reheat.

(2) No mist extractor from scrubber.

(3) No heat losses from ductwork and stack.

(4) New 500-MW power plant.



(this may translate to scrubber downtime and resulting boiler load reduction) has not been factored into the economic analysis. Since indirect hot air injection exhibits better reliability than inline reheat, this is another factor that may make indirect hot air injection competitive with other reheat systems.

The following results are noted (for the bases given in Table 51):

- (1) Inline and EGR reheat are generally lower cost (annualized cost) systems than direct combustion and indirect hot air. EGR reheat, however, has not been tested commercially.
- (2) The better reliability of the indirect hot air reheat system (compared to inline) may make indirect hot air competitive with the other systems for some users.
- (3) Since the direct combustion system ARR is highly dependent on fuels which may be subject to availability constraints and high cost escalation, its use in new power plants is expected to be limited.

Impact of Assumptions on Economics

It is recognized that all power plants are different and, consequently, the reheat requirements used in these plants will also be different. The bases (presented in Tables 38 and 39 and Appendix E) used to develop the preceding economics could not and do not apply to every possible reheat situation. An evaluation of how changes in design parameters affect the costs associated with an inline reheater was conducted. The cost estimate for the "base case" inline reheater is based on the following:

- (1) 9000 Btu/hr plant heat rate
- (2) 50°F of reheat
- (3) No heat losses from the stack and duct work (downstream of the mist eliminator)
- (4) No mist entrainment from the mist eliminator

- (5) Carbon steel tubes in the reheater
- (6) New 500-MW power plant
- (7) 165 psia, dry, saturated steam as reheat steam

These assumptions result in a required heat input of 66.8×10^6 Btu/hr, a capital requirement of \$1,090,000, and an annual revenue requirement of \$1,520,000 (see Table 40). Several differences in these assumptions were evaluated as described below and the results are presented in Table 52.

Case A - The only base case values changed were related to the entrainment mist and heat loss assumptions. The entrained mist from the scrubber was taken as 0.802 gr/scf. Heat losses from the duct and stack equivalent to a 5°F flue gas temperature drop were also assumed. These values increased the base case reheat requirement from 66.8×10^6 to 82.4×10^6 Btu/hr and the annual revenue requirement from $\$1.52 \times 10^6$ to $\$1.87 \times 10^6$.

Case B - In addition to the heat losses that were assumed in Case A, the reheater tube material was assumed to be 316 stainless steel instead of carbon steel (base case). The change resulted in increasing the annual revenue requirement compared to the base case by about 26 percent. The capital requirement of the reheat exchanger increased significantly also.

Case C - In this case the entrained mist was assumed to be 0.802 gr/scf. Heat losses were equivalent to a 5°F drop in flue gas temperature. The reheater tube material was 316 stainless steel, while a plant heat rate of 10,350 base case reheat energy requirement from 66.8×10^6 Btu/hr to 95.9×10^6 Btu/hr and the annual revenue requirement from $\$1.52 \times 10^6$ to $\$2.20 \times 10^6$ (or a 45 percent increase over the base case ARR).

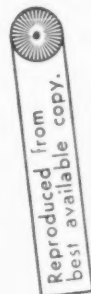
TABLE 52. IMPACT OF ASSUMPTIONS ON ECONOMICS OF 50°F REHEAT WITH INLINE REHEAT SYSTEM

System Heat Losses, % ^a	Concentration, g/sec	Heat Input, 10 ⁶ Btu/hr	Plant Heat Rate, Btu/lb ^b	Capital Investment, 10 ⁶ \$	Total Reheat Heat Input, 10 ⁶ Btu/hr	Estimated Annual Requirement, 10 ⁶ \$/year
Base Case ^b	0	0	9000	1.09	66.8	1.52
Case A	5	6.7	9000	1.36	82.4	1.87
Case B	5	6.7	9000	1.84	82.4	31.91
Case C	5	8.9	10150	32.12	95.9	57.20

^a For vaporization

^b Base Case Characteristics:

- (1) 165 psia, dry, saturated steam
- (2) Carbon steel tubes
- (3) New 500 MW plant



REFERENCES

1. Choi, P. S. K., et al. Stack Gas Reheat for Wet Flue Gas Desulfurization Systems. Final Report. EPRI FR-361, RP 209-2. Battelle Columbus Laboratory, Columbus, OH, 1977.
2. Laseke, Bernard A., Jr. EPA Utility FGD Survey: December 1977 - January 1978. EPA Contract No. 68-01-4147, Task 3, EPA 600/7-78-051a. PEDCo Environmental, Cincinnati, OH, March 1978.
3. Laseke, Bernard A., Jr. Survey of Flue Gas Desulfurization Systems: Green River Station, Kentucky Utilities. Final Report. EPA Contract No. 68-01-4147, Task 3, EPA 600/7-78-048e. PEDCo Environmental, Cincinnati, OH, March 1978.
4. Laseke, Bernard A., Jr. Survey of Flue Gas Desulfurization Systems: Will County Station, Commonwealth Edison Co. Final Report. EPA Contract No. 68-01-4147, Task 3, EPA 600/7-78-048b. PEDCo Environmental, Cincinnati, OH, March 1978.
5. Laseke, Bernard A., Jr. Survey of Flue Gas Desulfurization Systems: St. Clair Station, Detroit Edison Co. Final Report. EPA Contract No. 68-01-4147, EPA 600/7-78-048c. PEDCo Environmental, Cincinnati, OH, March 1978.
6. Isaacs, Gerald A. and Fouad K. Zada. Survey of Flue Gas Desulfurization Systems: Hawthorn Station, Kansas City Power and Light Co. EPA 650/2-75-057-h. PEDCo Environmental Specialists, Inc., Cincinnati, OH, September 1975.
7. Laseke, Bernard A., Jr. Survey of Flue Gas Desulfurization Systems: La Cygne Station, Kansas City Power and Light Co., Final Report. EPA Contract No. 68-01-4147, Task 3, EPA 600/7-78-048d. PEDCo Environmental, Cincinnati, OH, March 1978.
8. McDaniel, Clifford F. "La Cygne Station Unit No. 1 Wet Scrubber Operating Experience", Presented at the Utility Scrubber Conference, Denver, CO, March 1978.
9. Isaacs, Gerald A. and Fouad K. Zada. Survey of Flue Gas Desulfurization Systems: Lawrence Power Station, Kansas Power and Light Co. EPA 650/2-76-057-e. PEDCo Environmental Specialists, Inc., Cincinnati, OH, September 1975.

10. Ayer, Franklin, A. Flue Gas Desulfurization, Hollywood, FL, November 1977, Symposium Proceedings, 2 volumes. EPA Contract No. 68-02-2612, Task 38, EPA 600/7-78-058a,b. Research Triangle Institute, Research Triangle Park, NC, March 1978.
11. Proceedings: Symposium on Flue Gas Desulfurization, New Orleans, March 1976. IERL, U.S. Environmental Protection Agency, Research Triangle Park, NC, May 1976.
12. Leivo, C. C. Flue Gas Desulfurization Systems: Design and Operating Considerations, Final Report, 2 volumes. EPA Contract No. 68-02-2612, Task 2, EPA 600/7-78-030a,b. Bechtel Corp., San Francisco, CA, March 1978.
13. Gerstle, Richard W. and Gerald A. Isaacs. Survey of Flue Gas Desulfurization Systems: Reid Gardner Station, Nevada Power Co. EPA 650/2-75-057. PEDCo Environmental Specialists, Inc., Cincinnati, OH, October 1975.
14. Gibbs and Hill, Inc. Omaha Public Power District Site Selection Studies for Pumped Storage Addition. New York, November 1974.
15. Isaacs, Gerald A. Survey of Flue Gas Desulfurization Systems: Eddystone Station, Philadelphia Electric Co. PEDCo Environmental Specialists, Inc., Cincinnati, OH, September 1975.
16. Isaacs, Gerald A. Survey of Flue Gas Desulfurization Systems: Dickerson Station, Potomac Electric Power Co. PEDCo Environmental Specialists, Inc., Cincinnati, OH, September 1975.
17. Pacific Chemical Engineering Congress (PACHEC '77), Second, Denver, CO, August 1977, Proceedings, volume 1. American Institute of Chemical Engineers, New York, 1977.
18. Bechtel Corp. Flue Gas Desulfurization: Implications of SO₂ Removal Requirements, Coal Properties and Reheat. Draft Report. EPA Contract No. 68-02-2616. San Francisco, CA, September 1977.
19. PEDCo Environmental, Inc. Flue Gas Desulfurization Systems. Summary Report, June-July 1977. EPA Contract No. 68-01-4147, Task No. 3, Cincinnati, OH, 1977.
20. Rohr, F. W. Suppression of the Steam Plume From Incinerator Stacks. In: National Incinerator Conference, New York, May 1968, Proceedings. New York, ASME, 1968, pp. 216-24.
21. Rohr, Fred W. Suppressing Scrubber Steam Plume. Pollution Engineering 1 (1), 1969. pp. 20-22.

22. Ellison, W. Designing Large Wet-Scrubber Systems. Power 116 (2), 1972, pp. 67-69.
23. Blum, A. Drizzle Precipitation From Water Cooling Tower. Engineer, August 6, 1948, pp. 128-130.
24. Overcamp, Thomas J. and David P. Hoult. Precipitation in the Wake of Cooling Towers. Atmospheric Environment 5, September 1971, pp. 751-765.
25. Martin, A. and F. R. Barber. Measurements of Precipitation Downwind of Cooling Towers. Atmospheric Environment 8, 1974, pp. 373-381.
26. Busse, A. D. and J. R. Zimmerman. User's Guide for the Climatological Dispersion Model. Environmental Protection Agency, NERC, OR&D, Research Triangle Park, NC, December 1973.
27. Turner, D. B. Workbook of Atmospheric Dispersion Estimates, U.S. Environmental Protection Agency, Office of Air Programs, Publication No. AP-26, 1970.
28. McGlamery, G. G., et al. Detailed Cost Estimates for Advanced Effluent Desulfurization Processes. Final Report. EPA 600/2-75-006. TVA, Muscle Shoals, AL, January 1975.
29. Calvin, E. L. A Process Cost Estimate for Limestone Slurry Scrubbing of Flue Gas. Final Report. EPA-R2-73-148a. Catalytic, Inc., Charlotte, NC, 1973.
30. Calvin, E. L. A Process Cost Estimate for Limestone Slurry Scrubbing of Flue Gas, Part II, Detailed Estimate Sheets. Final Report. Catalytic, Inc., Charlotte, NC, 1973.
31. Wigley, T. M. A Numerical Analysis of the Effect of Condensation on Plume Rise. Journal of Applied Methodology, Volume 14, 1975, pp. 1105-1109.
32. Briggs, G. A. Some Recent Analyses of Plume Rise Observation. In: Proceedings of the Second International Clean Air Congress. England, H. M. and W. T. Barry (ed.), 1971.
33. Bechtel Power Corporation, San Francisco Power Division. Coal-Fired Power Plant Capital Cost Estimates. Final Report. EPRI AF-342, State-of-the-Art 75-329. San Francisco, CA, January 1977.
34. Perry, John H. Chemical Engineers Handbook, 5th Edition. McGraw-Hill, New York, 1973.
35. Guthrie, K. M. Process Plant Estimating Evaluation and Control. Craftsman Book Co., Solana Beach, CA, 1974.

36. Peters, Max S. and Klaus D. Timmerhaus. Plant Design and Economics for Chemical Engineers, 2nd Edition. McGraw-Hill, New York, 1968.
37. Ponder, Thomas C., et al. Simplified Procedures for Estimating Flue Gas Desulfurization System Costs. EPA 600/2-76-150, EPA Contract No. 68-02-1321, Task 12. PEDCo Environmental Specialists, Inc., Cincinnati, OH, June 1976.

The following companies and individuals contributed their advice and assistance during the course of this project.

Alabama Electric Coop. - Tombigbee Station - A. Wells
Allegheney Power System - Pleasants Station - T. L. Misner
American Air Filter - Dan Josephs
Arizona Electric Power Coop. - Apache Station - J. Wharrie, L. D. Porter
Arizona Public Service - Cholla Station - C. Walker
- Four Corners Station - Mr. Haelbig
Babcock and Wilcox - H. M. Majdeski
Basin Electric Power Coop. - Antelope Valley and Laramie River Stations -
R. L. Eriksen
Bechtel National, Inc. - R. M. Sherwin
Big Rivers Electric Corp. - Reid Station - T. Carter
Brazos Electric Power Corp. - San Miguel Station - D. Boyle
Buffalo Forge Co. - F. Heinzmann
Burns and McDonnell - D. Froelich, J. Landwehr, B. Thompson
Burns and Roe, Inc. - J. Whipple
Central Illinois Light Co. - Duck Creek Station - L. H. Haynes, K. Swahlstedt
Central Illinois Public Service - Newton Station - J. Slavin
Columbus and Southern Ohio Electric Co. - Conesville Station - R. E. Ruby
Combustion Engineering - J. R. Martin
Commonwealth Edison - Powerton Station - C. C. Johnson
- Will County Station - J. Reid
Copes-Vulcan - T. Shortser
Davy Powergas, Inc. - L. H. Grives, R. I. Pedroso
Delmarva Power Co. - Delaware City Station - B. McConnell
Detroit Edison Co. - St. Clair Station - J. E. Myers
Diamond Power Specialty Corp. - L. Palmer
Duquesne Light Co. - Elrama and Phillips Stations - R. D. O'Hara
Environeering, Inc. - S. V. D'Souza
Indianapolis Power and Light Co. - Petersburg Station - Mr. Readle
Kansas City Power and Light Co. - Hawthorn Station - L. L. Marks
- La Cygne Station - C. F. McDaniel, S. Hedges
Kansas Power and Light Co. - Jeffery Station - L. Brunton
- Lawrence Station - R. Teeters
Kentucky Utilities - Green River Station - J. W. Reisinger
Kinetics Engineering - B. Hedricks
Louisville Gas and Electric Co. - Cane Run, Mill Creek, and Paddy's Run
Stations - R. P. Van Ness
Montana Power Co. - Colstrip Station - M. Hofacher, B. Lewis, E. Handell
Nevada Power Co. - Reid Gardner Station - T. Leavitt
Niagara Mohawk Power Coop. - Huntley Station - W. C. Hiestand
Northern Indiana Public Service - Bailly Station - D. Kuhn
- D. H. Mitchell Station - E. L. Manns
Northern States Power Co. - Sherburne Co. Station - R. J. Kruger, L. P.
Gordon
Otter Tail Power Co. - Coyote Station - T. Graumann

Pacific Power and Light Co. - Dave Johnson Station - T. M. Phillips
 Pennsylvania Power Co. - Bruce Mansfield Station - D. Thomas
 Philadelphia Electric Co. - Cromby Station - E. Boyer
 - Eddystone Station - B. Helt
 Potomac Electric and Power - Dickerson Station - W. C. Jenson
 Public Service Company of Colorado - Arapaho, Cherokee, and Valmont
 Stations - K. Barnett
 Public Service Company of Indiana - Gibson Station - L. W. Leath
 Public Service Company of New Mexico - San Juan Station - T. Warnke,
 J. T. Ferrill
 Pullman-Kellogg - J. C. Yarze
 Pullman Power Products - E. Yondy
 Ralph M. Parsons - N. Alispones
 Research-Cottrell - Dr. R. L. Kent
 Salt River Project - Coronado Station - R. F. Durning
 South Carolina Public Service Co. - Winyah Station - C. L. Osborne
 Southern Illinois Power Coop. - Marion Station - Mr. Stafford
 Southern Indiana Gas and Electric - AB Station - J. Milhorn
 Southern Mississippi Electric - R. D. Morrow Station - C. A. Webb, Jr.
 Springfield City Utilities - Southwest Station - L. Killingsworth
 Springfield Water, Light and Power - Dallman Station - C. J. Saladino
 Tennessee Valley Authority - Shawnee and Widows Creek Stations -
 Dr. G. A. Hollinden, G. Munson, R. Robards
 Texas Municipal Public Agency - Gibbons Creek Station - D. Howard
 Texas Utilities Co. - Monticello Station - C. L. Merka
 Tranter, Inc., Texas Division - Gerry Delaney
 United Engineers and Constructors, Inc. - G. Frey
 United Power Association - Coal Creek Station - W. R. Smit, J. Weeda
 UOP, Inc. - Dr. N. Ostroff
 Utah Power and Light Co. - Emery Station - A. L. Perry
 - Huntington Station - M. W. Kenney, G. N. Lacey
 Wisconsin Power and Light Co. - Columbia Station - S. S. Frey
 Zurn Industries, Inc. - A. Broski

APPENDIX A

DESCRIPTION OF RADIAN'S DISPERSION AND WET PLUME MODELS

APPENDIX A

DESCRIPTION OF RADIAN'S DISPERSION AND WET PLUME MODELS

DESCRIPTION OF WET PLUME MODEL

Radian's Wet Plume Model was used to analyze the effect of reheat on the length of visible plumes and the concentration of condensed water in the plume with regard to possible rainout. The Wet Plume Model is based on the set of conservation equations presented by Wigley in 1975.³¹ The set consists of equations of conservation of mass, momentum, and energy, and an assumed entrainment equation. Major assumptions associated with the model are that the plume has a definite boundary and that the properties of the plume are uniform in a cross section. These assumptions allow all of the equations to be written as ordinary differential equations rather than the more complicated partial differential equations.

The equations are stated here for completeness but will not be discussed in detail.

$$\frac{d}{dt} (VR^2) = \frac{2v_e}{R} VR^2 \quad (A-1)$$

$$\frac{d}{dt} \left[VR^2 (q - q_o + \sigma) \right] = - \frac{dq_o}{dz} VR^2 w \quad (A-2)$$

$$\frac{d}{dt} \left[VR^2 g \left(\frac{T^* - T_o^*}{T_o^*} - \frac{L\sigma}{C_p T_o^*} \right) \right] = -N^2 VR^2 w \quad (A-3)$$

$$\frac{d}{dt} \left[VR^2 w \right] = gVR^2 \left(\frac{T^* - T_o^*}{T_o^*} - \sigma \right) \quad (A-4)$$

$$\frac{d}{dt} \left[VR^2 v \right] = U_o \frac{d}{dt} (VR^2) \quad (A-5)$$

$$\frac{dz}{dt} = w \quad (A-6)$$

$$\frac{dx}{dt} = v \quad (A-7)$$

The symbols are identified as follows:

- t = independent variable, time
- V = centerline plume velocity
- R = radius of the plume
- v_e = entrainment velocity
- q = specific humidity
- v, w = x and z components of the plume velocity, respectively
- σ = liquid water mixing ratio
- g = acceleration due to gravity
- T* = virtual temperature
- L = latent heat of vaporization of water
- N = the Brunt-Väisälä frequency
- U = ambient wind velocity
- Subscript o = atmospheric variable
- No subscript = plume variable

The entrainment speed v_e is given by

$$v_e = \alpha |w| \quad (A-8)$$

where α is an empirical constant, and the Brunt-Väisälä frequency is given by

$$N^2 = \left[\frac{g}{T_o} (\Gamma_{ad} - \Gamma_o) \right] \quad (A-9)$$

where Γ_{ad} is the adiabatic lapse rate and Γ_o is the actual lapse rate.

Equation A-1 is the entrainment assumption, Equation A-2 is the total water mass balance equation, and Equation A-3 is the energy conservation equation. The conservation of vertical and horizontal momentum are given by Equations A-4 and A-5, respectively, and the spatial locations are defined by Equations A-6 and A-7.

Note that these equations do not address the momentum-dominated dynamics explicitly. It has been generally assumed by previous investigators that this effect can be ignored in favor of the buoyancy-dominated dynamics.

These equations are valid only for a relatively short distance downwind of the stack. The results, discussed in Section 5, become invalid at about 1640 feet (500 meters) downwind of the source.

DESCRIPTION GAUSS/X-CURVE PLUME MODELING PROGRAM (THREE-HOUR CONCENTRATIONS)

With the use of Radian's Gauss/X-Curve plume modeling program, the effect of reheat on the short term (three-hour) SO_2 and NO_x ground-level concentrations was analyzed for two atmospheric stabilities, unstable and neutral. The algorithms used in this model are similar to those expressions presented by Turner in Workbook of Atmospheric Dispersion Estimates.²⁷ The time-averaged ground-level concentration is given by:

$$X(x,y;H) = \frac{Q}{\pi u \sigma_y \sigma_z} \exp \left[-\frac{1}{2} \left(\frac{y}{\sigma_y} \right)^2 - \frac{1}{2} \left(\frac{H}{\sigma_z} \right)^2 \right] \quad (A-10)$$

where: χ = the pollutant concentration
 x = distance downwind
 y = radius of the plume at (x, H)
 H = height of plume centerline (relative to ground-level)
 u = wind speed
 Q = pollutant source strength
 σ_y = horizontal dispersion coefficient
 σ_z = vertical dispersion coefficient

The plume rise formula used in the study was derived by Briggs (1971)³²:

$$H = h + 1.6F^{1/3}u^{-1}x^{2/3} \text{ when } x \leq 3.5x^*$$

and

$$H = h + 1.6F^{1/3}u^{-1}(3.5x^*)^{2/3} \text{ when } x > 3.5x^* \quad (A-11)$$

and $x^* = 14F^{5/8} \text{ when } F \leq 55$

$$x^* = 34F^{2/5} \text{ when } F > 55$$

where: H = effective stack height (stack height plus plume rise)
 h = stack height
 x = downwind distance
 u = wind speed
 F = buoyancy flux

The total buoyancy flux, F , is the only term affected by the reheat configuration that is used and is given by

$$F = g V_s R_s^2 \left(\frac{T_s - T_a}{T_s} \right) \quad (A-12)$$

where: V_s = velocity of flue gas exiting the stack
 g = local acceleration due to gravity
 R_s = stack radius
 T_s = gas temperature exiting the stack
 T_a = ambient air temperature

The plume dispersion coefficients used in the model were determined from the Pasquill-Gifford curves presented by Turner in the previously mentioned publication.

DESCRIPTION OF GAUSS/X-STAR MODEL (ANNUAL AVERAGE CONCENTRATIONS)

Annual average concentrations were estimated with the Radian Gauss/X-Star program which utilizes the algorithm presented by Busse and Zimmerman in 1973.²⁶ The basis for this program is annual average ground-level concentration due to a single source which is given by

$$C_g = \frac{16}{2\pi} \sum_{\ell=1}^6 \sum_{m=1}^6 \frac{\phi(k, \ell, m) G S(\sigma; U_\ell, P_m)}{\sigma} \quad (A-13)$$

where: C_g = annual average ground-level concentration
 $\phi(k, \ell, m)$ = joint frequency function (dimensionless)
 k = wind section appropriate to the source (dimensionless)
 ℓ = index identifying the wind speed class (dimensionless)
 m = index identifying the class of the Pasquill stability category
 G = pollutant emission rate of the source
 S = dispersion function
 σ = distance from the receptor to the source
 U_ℓ = representative wind speed
 P_m = Pasquill stability category

The dispersion function, S, in this expression is given by:

$$S(\rho; U_\ell, P_m) = \frac{2}{\sqrt{2\pi} U_\ell \sigma_z} \exp \left[-\frac{1}{2} \left(\frac{H}{\sigma_z} \right)^2 \right] \quad (\text{seconds/meter}^2) \quad (\text{A-14})$$

when $\sigma_z \leq 0.8L$

and

$$S(\rho; U_\ell, P_m) = \frac{1}{U_\ell L} \quad \text{when } \sigma_z > 0.8L \quad (\text{A-15})$$

where: H = plume centerline height
 L = afternoon mixing height
 σ_z = vertical dispersion coefficient

This expression is the basis for a statistical technique that uses multiple years of NWS meteorological observations to develop a frequency distribution. The data used for this exercise were collected at Wayne City, Michigan (near Detroit) over the period 1959 - 1968.

APPENDIX B
QUESTIONNAIRE FORMS

APPENDIX B
QUESTIONNAIRE FORMS

Presented in this appendix are the questionnaires sent to A/E firms, FGD process vendors, and utilities. The companies that were sent questionnaires are listed.

A/E QUESTIONNAIRE

The questionnaire sent to A/E-consulting firms is presented as Attachment I. The companies that received the questionnaires are listed below. Seven out of eleven companies responded.

Bechtel Corporation
Black and Veatch
Burns and McDonnell
Burns and Roe
Combustion Engineering
Peabody Engineering
Pullman Kellogg
Ralph M. Parsons
Stearns-Roger
United Engineers and Constructors, Inc.
UOP Incorporated

Attachment I

A&E/CONSULTANT QUESTIONNAIRE
WET SCRUBBING FLUE GAS REHEAT SYSTEMS

I. ORGANIZATION INFORMATION

A. Company Name _____

Address _____
city state zip code

Telephone number _____

B. Person Completing Form _____
name

_____ title

II. REHEAT RECOMMENDATIONS

A. Do you recommend that reheat always be used? _____

B. Do you specify reheat systems only when required by the customer?

C. Do you recommend against reheat? If so, why? _____

III. REHEAT EQUIPMENT CONFIGURATION

A. Which Type of Reheat Equipment Do You Recommend (check one)

1. Direct Combustion (see B) _____
2. Indirect Hot Air (see C) _____
3. Inline (see D) _____
4. Bypass (see E) _____
5. Other (see F) _____

Items B-G are for your recommendations on specific equipment items, configurations, and philosophies.

B. Direct Combustion Reheat

1. Fuel type _____
2. Combustion chamber type *(check one)*
 - Internal _____
 - External _____
3. Mixing chamber
 - Materials of construction _____
 - Mixing device _____
4. Recommended nozzle type and material of construction _____

5. Control philosophy _____

C. Indirect Hot Air Injection Reheat

1. Heat exchanger type _____
2. Materials of construction _____
3. Heating medium _____
4. Recommended exchanger configuration _____
5. Mixing chamber device _____
6. Control philosophy _____

D. Inline Reheat

1. Heat exchanger type _____
2. Materials of construction _____
3. Heating medium _____
4. Recommended exchanger configuration _____

5. Cleaning devices _____
6. Control philosophy _____
- E. Bypass Reheat
1. Control philosophy _____
2. Supplemental reheat recommended _____
- F. Other Reheat Methods _____
- _____
- _____
- _____
- _____
- _____
- G. Ductwork and Stack Design
1. Materials of construction _____
- _____
2. Insulation (*R value*) _____
- _____
3. Duct gas velocity (*ft/sec*) _____
- _____
4. Stack discharge velocity (*ft/sec*) _____
5. Temperature drop between reheat and stack outlet (*°F*) _____
- _____
6. Mist eliminator type _____
name
7. Mist eliminator location (*check one*)
- a) Horizontal duct _____
- b) Vertical duct _____

- V. What is your experience concerning the problems reheat systems have had and how was the reliability improved. Have you discontinued any reheat configurations or have you developed any new technology? Please explain (all information will be held in complete confidence).

- VI. What fraction of the total capital cost of an FGD System does the reheat system represent?
-

What fraction of the total operating cost? _____

What fraction of the total maintenance cost? _____

- VII. Copies of any sales or technical publications which you distribute would be very beneficial.

FGD PROCESS VENDOR QUESTIONNAIRE

Attachment II is the questionnaire sent to FGD process vendors. The companies to whom the questionnaire was sent are listed below. Five out of the seven companies responded.

American Air Filter
Babcock and Wilcox
Chemico
Davy Powergas

Arthur D. Little
Environeering, Inc.
Research Cottrell

ELECTRIC UTILITY (REHEAT USER) QUESTIONNAIRE

Attachment III is the questionnaire sent to utilities. Utilities who received the questionnaires are listed below. Twenty-six out of the forty-six questionnaires were returned.

Alabama Electric Co-op., Inc.
Allegheny Power System
Arizona Electric Power Co-op.
Arizona Public Service Co.
Basin Electric Power Co-op.
Big Rivers Electric Corp.
Brazos Electric Power Co-op.
Central Illinois Light Co.
Cincinnati Gas and Electric Co.
Colorado Ute Electric Association
Columbus and South Ohio Electric Co.
Commonwealth Edison Co.
Duquesne Light Co.
Eastern Kentucky Power Co-op.
Indianapolis Power and Light Co.
Kansas City Power and Light Co.

Kansas Power and Light Co.
Kentucky Utilities Co.
Louisville Gas and Electric
Minnesota Power and Light Co.
Minnkota Power Co-op.
Montana Power Co.
Nevada Power Co.
New England Electric System
Niagra Mohawk Power Corp.
Northern Indiana Public Service
Northern States Power Co.
Otter Tail Power Co.
Pacific Power and Light Co.
Pennsylvania Power Co.
Philadelphia Electric Co.
Potomac Electric Power Co.

Public Service Co. of Indiana
Public Service Co. of New Mexico
Salt River Project
South Carolina Public Service Authority
Southern Illinois Power Co-op.
Southern Indiana Gas and Electric
South Mississippi Electric Power Association
Springfield City Utilities
Tennessee Valley Authority
Texas Power and Light Co.
Texas Utilities Co.
United Power Association
Utah Power and Light Co.
Wisconsin Power and Light Co.

Attachment II

FGD VENDOR QUESTIONNAIRE
WET SCRUBBING FLUE GAS REHEAT SYSTEMS

I. ORGANIZATION INFORMATION

A. Company Name _____

Address _____ city state zip code

Telephone number _____

B. Person Completing Form _____
name

title

II. TYPE OF FLUE GAS DESULFURIZATION SYSTEM (*check one*)

A. Regenerable

1. Wellman-Lord _____

2. Mag-Ox _____

3. Other _____
name

B. Nonregenerable

1. Lime/limestone _____

2. Double Alkali _____

3. Other _____
name

The following section concerns your design recommendations to present and prospective customers. Drawings or descriptive literature would be beneficial.

III. MIST ELIMINATOR, DUCT, AND STACK DESIGN

- A. Recommended Mist Eliminator Type _____
name
- B. Recommended Mist Eliminator Location (*check one*)
1. Horizontal duct _____
 2. Vertical duct _____
- C. Expected Outlet Mist Eliminator Loadings
1. Solids (*gr/scf*) _____
 2. Condensed Vapor (*gr/scf*) _____
- D. Ductwork and Stack Design
1. Recommended materials of construction _____

 2. Recommended insulation thickness or "R" value _____

 3. Duct gas velocity (*ft/sec*) _____

 4. Stack discharge velocity (*ft/sec*) _____
 5. Expected temperature drop between reheat and stack outlet (*°F*) _____

I/. STACK GAS REHEAT

- A. Always Recommended Reheat _____
- B. Design Only at Customer's Request _____
- C. Never Recommend Reheat _____
- D. If reheat is not recommended, please explain _____
- _____

V. RECOMMENDED REHEAT EQUIPMENT CONFIGURATION

- A. Type of Reheat Equipment (*check one*)
1. Direct combustion (*see B*) _____
2. Indirect hot air (*see C*) _____
3. Inline (*see D*) _____
4. Bypass (*see E*) _____
5. Other (*see F*) _____

The following sections (B-F) are for your recommendations for specific equipment and configurations.

B. Direct Combustion Reheat

1. Fuel type _____
2. Combustion chamber type (*check one*)
- Internal _____
- External _____
3. Mixing chamber
- Materials of construction _____
- Mixing device _____
4. Recommended nozzle type and materials of construction _____
- _____

5. Control philosophy _____

C. Indirect Hot Air Injection Reheat

1. Heat exchanger type _____
2. Materials of construction _____
3. Heating medium _____
4. Recommended exchanger configuration _____
5. Mixing chamber device _____
6. Control philosophy _____

D. Inline Reheat

1. Heat exchanger type _____
2. Materials of construction _____
3. Heating medium _____
4. Recommended exchanger configuration _____
5. Cleaning devices _____
6. Control philosophy _____

E. Bypass Reheat

1. Control philosophy _____
2. Supplemental reheat recommended _____

F. Other Reheat Methods _____

VI. QUANTITY OF REHEAT

If not specified by the customer, how do you estimate the quantity of reheat required?

VII. REHEATER SYSTEM RELIABILITY EXPERIENCE

The following questions relate to your experience with reheat systems.

A. Corrosion

1. Tubes _____

Materials of construction _____

2. Ductwork _____

3. Stack _____

B. Solids Deposition _____

Removal Equipment & Location _____

C. Reheater Material Availability _____

D. Replacement Parts Availability _____

E. Maintenance Requirements *(Include reheater, downstream fans and equipment)*

VIII. What fraction of the total Capital Cost of an FGD System does the reheat system represent?

What fraction of the total operating cost? _____

What fraction of the total maintenance cost? _____

IX. Copies of any sales or technical publications which you distribute would be very beneficial.

IX. USERS OF YOUR EQUIPMENT

PedCo Environmental has identified the following utilities as present or future users of your equipment. To establish the trends in stack gas reheat, please complete the following table.

Utility	Type of reheat	Heating medium	Degree of reheat

Attachment III

USER QUESTIONNAIRE

WET SCRUBBING-FLUE GAS REHEAT SYSTEMS

I. ORGANIZATION INFORMATION

- A. Company Name _____
- Address _____ city state zip code
- Telephone Number _____
- B. Person Completing Form _____
- name
- _____
- title

II. FGD/REHEAT DESIGN AND PHILOSOPHY

- A. FGD System Type
1. Full-scale unit
 - a) New _____
 - b) Retrofit _____
 2. Demonstration unit _____
 3. Pilot-plant unit _____
 4. Other (please describe)

- B. Reheat System (please explain)
1. Recommend and use _____

2. Recommend but do not use _____

3. Do not recommend _____

III. TYPE OF FLUE GAS DESULFURIZATION SYSTEM (*check one*)

A. Wet Absorption

1. Regenerable

- a) Wellman-Lord _____
- b) Mag-Ox _____
- c) Other _____
name

2. Nonregenerable

- a) Lime/limestone _____
- b) Double alkali _____
- c) Other _____
name

B. Vendor _____
name

address

C. Installation Date _____

1. New _____

2. Retrofit _____

IV. SYSTEM DESIGN

A. Mist Eliminator

1. Mist eliminator type _____
name
2. Mist eliminator location (*check one*)
 - a) Horizontal duct _____
 - b) Vertical duct _____
3. Outlet mist eliminator loadings
 - a) Solids (*gr/scf*) _____
 - b) Condensed vapor (*gr/scf*) _____

B. Ductwork and Stack Design

1. Materials of construction _____

3. Duct size (*ft x ft*) or gas velocity (*ft/sec*) _____

4. Stack discharge diameter (*ft*) _____
5. Temperature drop between reheat and stack outlet (*°F*) _____

6. Stack height (*ft*) _____

C. Flue Gas Properties

1. Gas analysis, scrubber outlet, (*volumetric analysis %*)

N ₂ _____	H ₂ O _____
HCl _____	SO ₂ _____
O ₂ _____	CO ₂ _____

2. Temperature ($^{\circ}\text{F}$) _____

3. Volumetric flowrate (acfm) _____

V. REHEAT EQUIPMENT CONFIGURATION

A. Type of Reheat Equipment (check one)

1. Direct (see B) _____

2. Indirect hot air injection (see C) _____

3. Inline (see D) _____

4. Bypass (see E) _____

B. Direct

1. Fuel type _____

2. Fuel analysis

Fuel oil
(gravimetric
analysis, %)

Natural gas (volumetric analysis, %)
(Please list constituents & percentages)

C _____

H _____

N _____

O _____

Cl _____

S _____

3. Heating value (Please indicate higher or lower value)

4. Consumption rate (Please add units) _____

5. Combustion chamber type _____

6. Excess Air (%) _____

7. Gas temperature before mixing ($^{\circ}F$) _____

8. Resulting flue gas temperature after mixing ($^{\circ}F$) _____

C. Indirect hot air injection

1. Hot air properties

a) Flowrate (scfm) _____

b) Inlet temperature ($^{\circ}F$) _____

c) Outlet temperature ($^{\circ}F$) _____

d) Outlet specific humidity
($\frac{\text{lb water vapor}}{\text{lb dry air}}$) _____

e) Outlet pressure (psia) _____

2. Heating medium _____

a) Medium temperature ($^{\circ}F$) _____

b) Medium pressure (psig) _____

c) Consumption rate (lb/hr) _____
or
(scfm/hr) _____

d) Heating value or energy supplied
(Btu/lb) _____
or
(Btu/scfm) _____

3. Heat exchanger information

a) Tube size _____

b) Number of tubes/bank _____

c) Number of banks _____

d) Materials of construction _____

4. Mixing method _____

5. Resulting flue gas temperature ($^{\circ}F$) _____

D. Inline

1. Heating medium _____
 - a) Medium temperature ($^{\circ}F$) _____
 - b) Medium pressure (*psig*) _____
 - c) Consumption rate (*lb/hr*) _____
2. Heat exchangers
 - a) Tube size _____
 - b) Number of tubes/bank _____
 - c) Number of banks _____
 - d) Materials of construction _____
 - e) Tube cleaning device and schedule _____

3. Resulting flue gas temperature ($^{\circ}F$) _____

E. Bypass

1. Untreated flue gas temperature ($^{\circ}F$) _____
2. Untreated flue gas volume (*acfm*) _____
3. Resulting stack gas temperature ($^{\circ}F$) _____
4. SO_2 Analysis
 - a) Scrubber inlet _____ ppm
 - b) Scrubber outlet _____ ppm
 - c) Stack outlet _____ ppm

- F. Other Reheat Methods _____

G. Amount of Reheat

1. Required design temperature increase _____ ($^{\circ}F$)

2. Atmospheric conditions

a) Normal temperature range ($^{\circ}F$) _____

b) Normal pressure range (psi) _____

c) Normal wind speeds (mph) _____

d) Design plume rise (ft) _____

e) Discharge stack velocity (ft/sec) _____

f) Other pertinent information _____

3. Basis used for selection of amount of reheat _____

4. Reason(s) for selection of type of reheater _____

H. Reheater System Reliability Experience (*description*)

1. Equipment

a) Corrosion

1) Tubes _____

Materials of construction _____

2) Ductwork _____

3) Stack _____

b) Solids deposition _____

Removal equipment & location _____

c) Reheater material availability _____

d) Replacement parts availability _____

e) Maintenance requirements (*Include reheater, fans & downstream equipment*)

2. Reheat medium availability problems (*yes/no*)

a) Fuel oil _____

b) Natural gas _____

c) Other (*please specify*) _____

I. Plume Dispersion Problems (*yes/no*)

1. Ground-level pollutants _____

if yes, weather conditions
windspeed (*mph*) & directions _____

wet bulb temperature ($^{\circ}\text{F}$) _____

dry bulb temperature ($^{\circ}\text{F}$) _____

ground-level concentrations _____

2. Ground-level fog (*yes/no*) _____

if yes, frequency _____

duration _____

weather conditions: _____

3. Rain or moisture fallout (yes/no) _____

if yes, frequency _____

duration _____

weather conditions:

windspeed (mph) & direction _____

wet bulb temperature ($^{\circ}F$) _____

dry bulb temperature ($^{\circ}F$) _____

J. Reheater Costs

1. Capital costs

a) Equipment (\$) _____

b) Installation (\$) _____

2. Operating costs

a) Reheater duty (percentage of boiler availability) _____

b) Maintenance costs (\$/unit of measure) _____

c) Reheat medium cost (\$) _____

d) Reheat total cost (percent of boiler output) _____

For units using internal reheat medium, such as steam, please describe the steps necessary to establish the cost of the fuel. If steam is used, please indicate its source and condition (*pressure, temperature and quality if wet*).

VI. SUMMARY OF REHEAT EXPERIENCE

A. Summary of Operating Systems

The following space is for summary information concerning points raised on the preceding pages.

B. Related Experience

The following space is for information regarding past systems which have failed, and systems presently being designed.

APPENDIX C

GENERALIZED 500-MW STEAM CYCLE--DEVELOPMENT AND STEAM COST ANALYSIS

APPENDIX C

GENERALIZED 500-MW STEAM CYCLE--DEVELOPMENT AND STEAM COST ANALYSIS

There are several sources of heat available in a power plant to accomplish stack gas reheat (SGR). Examples are steam extracted from the turbine power cycle of a utility boiler, combustion of additional fuel, and addition of hot air. The use of extraction steam from the turbine is analyzed in this Appendix. Energy and material flows were calculated for a "hypothetical" 500-MW coal-fired power plant with wet scrubbing of stack gases and SGR of about 40°F.

The objective of this work is to show the trends associated with the use of low through high pressure extraction steams for SGR. While a particular cycle has been chosen for this example, the trends should hold for all cases. It is expected that high pressure steam will be more economical (compared to low pressure steam) with respect to design and cost of the reheater. However, high pressure steam will be more valuable (because of higher available energy) with respect to the turbine than the low pressure steam. This section will provide a methodology for estimating the cost of various quality steams. In Appendix D, the methodology for designing the reheat exchangers for various quality steams will be presented.

As discussed above, a "hypothetical" steam cycle was developed in order to assess the availability and costs of various steam levels that are applicable as reheat steam. The approach used to identify the applicable levels and to determine the impact on the steam cycle of using these steam levels for reheat consisted of:

- (1) Developing a base case steam cycle which corresponds to a new 500-MW power plant with no stack gas reheat (SGR)

- (2) Identifying the qualities of steam available for stack gas reheat (for this "hypothetical" steam cycle only)
- (3) Determining the amount of steam at available steam levels that is required for SGR and adjusting the base case steam cycle to reflect this requirement while maintaining the same 500 MW turbine output
- (4) Estimating the impacts on the steam cycle and the resulting costs of using reheat steam at the different quality levels (for the hypothetical cycle only).

DEVELOPMENT OF STEAM CYCLE

The boiler and turbine for new power plant installations can be designed with extraction steam (normally used for feedwater heating) used for SGR being taken into consideration in the manner described above. It is for the new power plant that the above technique best applies. For retrofit FGD/reheat installations, the boiler/turbine cycle will probably not be adjustable in the manner described. The resulting energy penalty (for retrofit cases) associated with extracting steam for SGR may range from the same as for the newly designed plant (best case) to loss of electrical power generation capability in proportion to work lost through the steam being extracted for reheat (worst case). In some retrofit cases main steam may have to be used for stack gas reheat steam.

This analysis is not intended to be a rigorous calculation of the costs of steam (at several conditions) within a new power plant. In a power plant steam is available at turbine exhaust conditions (value of Btu content is negligible), main steam conditions (value of Btu content is high), and several intermediate conditions (value of Btu content is between that of main steam and exhaust steam depending on available energy to produce work). The following steam cycle development and analysis is intended to provide a general methodology for assessing the relative value of various quality steams as SGR steam. These costs for several different quality steams will be used to estimate the total cost of reheating stack gases.

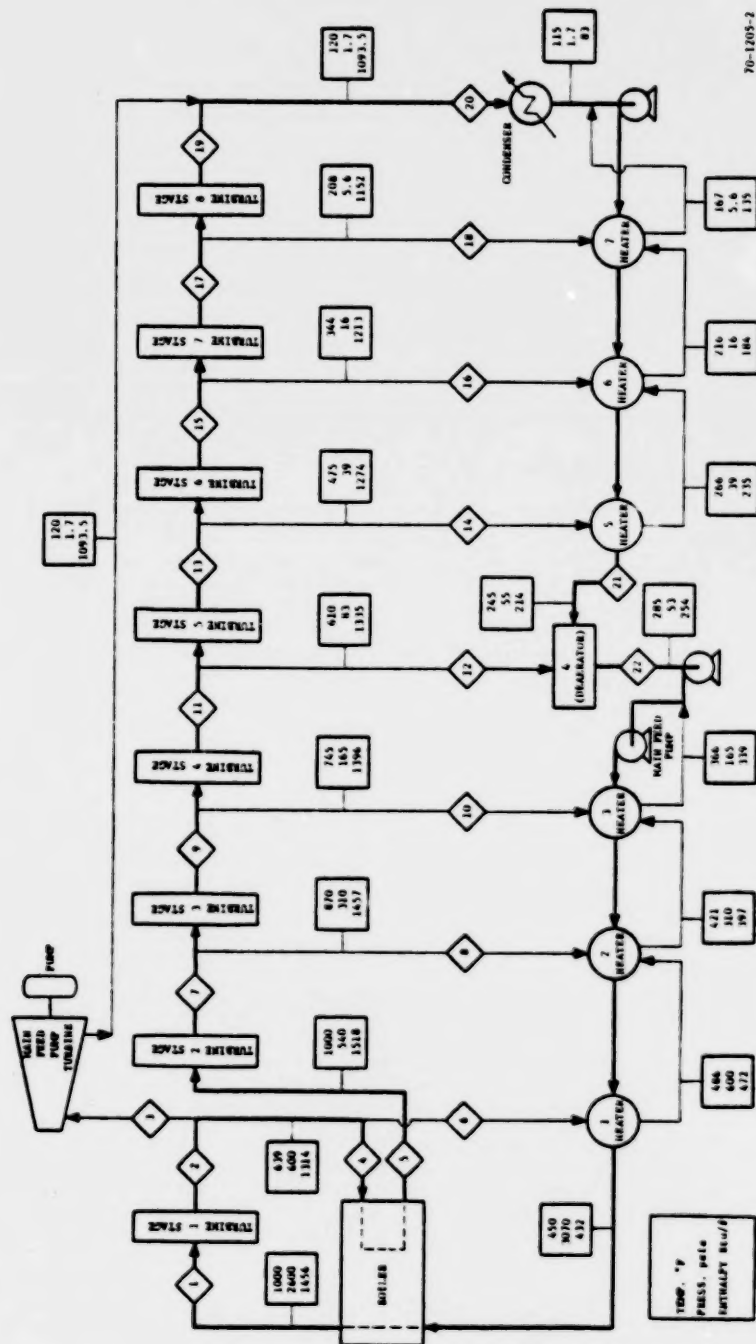
Base Case Steam Cycle and Approach for Extraction Steam Evaluation

Figure C-1 is a schematic of the base case steam cycle. High pressure steam from the boiler, Stream 1, passes through Stage 1 of the turbine. Each stage may actually be one or more turbine wheels. The main steam flow (4) is further superheated in the boiler. A minor flow goes to the feed pump turbine (3) and to heat the feedwater (6). The superheated steam (5) passes through Stages 2 through 8, respectively, of the turbine. After each stage, a small amount of steam is extracted and used to heat the boiler feedwater as it passes through the respective feedwater heaters. The main boiler feed pump is large enough that it is driven by a steam turbine.

The base case flow rates corresponding to Figure C-1 are presented in Table C-1, as are the bases for their development. Based on these assumptions, the turbine heat rate of the base case steam cycle is 9130 Btu/kWh. Assuming a boiler efficiency of 85 percent gives a gross station heat rate of 10,740 Btu/kWh on a fuel basis.

After the base case steam cycle was established, the effect of using extraction steam following all eight turbine stages as reheat steam was investigated. Main steam was considered too valuable to be used as stack gas reheat steam. Only operation of the plant at full load was evaluated. Analysis of each applicable steam level was based on the following approach:

- (1) The steam requirement to provide the reheat duty was calculated. The reheat duty was taken as 66.1×10^6 Btu/hr and would heat the stack gas about 40°F (assuming no heat losses from the stack gas through duct and stack walls and no mist carry-over from the scrubber).
- (2) Steam for flue gas reheat was taken at the same conditions as the extraction steam. It was also condensed at the same conditions as the extraction steam. The condensate from the flue gas reheater was added to the condensate from the appropriate feedwater heater.
- (3) The steam cycle was adjusted such that all stream enthalpies are identical to the base case enthalpies



70-1205-2

Figure C-1. Base case.

TABLE C-1. BASE CASE STEAM CYCLE FLOW RATES

Stream Number	lb/Hr	Stream Number	lb/Hr
1	3,781,260	12	115,130
2	3,781,260	13	2,907,280
3	205,780	14	120,300
4	3,391,140	15	2,786,980
5	3,391,140	16	120,300
6	184,340	17	2,666,630
7	3,391,140	18	120,300
8	184,340	19	2,546,380
9	3,206,800	20	2,752,160
10	184,340	21	2,113,060
11	3,022,460	22	3,228,240

Bases:

(1) A new coal-fired power plant.

(2) 500-MW net output.

(3) Steam cycle basis:

- Feedwater heating is accomplished with three closed, low pressure heaters, one direct contact desuperating heater, and three closed, high pressure heaters. The three low pressure feedwater heaters have equal steam flows.* The desuperating heater operates at 53 psia. The three high pressure heaters have equal steam flow rates.
- Throttle conditions are 1000°F, 2600 psia.
- Expansion in the first stage (high pressure turbine stage) is from throttle conditions to 600 psia at 90 percent efficiency.
- Steam is reheated to 1000°F after the first stage.
- Turbine exhausts at 3.5 in. Hg (1.7 psia), 98 percent quality steam.
- Lower stage efficiency is 75 percent with each stage exhibiting equal change in enthalpy. The seven extraction steam conditions were set in the same manner (i.e., after constant changes in enthalpy through the turbine). Refer to Figure C-1 for these extraction steam conditions.
- Feedwater enters economizer at 450°F.
- Main boiler feedwater pump is driven by auxiliary turbine using first stage extraction steam. Auxiliary turbine exhaust conditions are the same as exhaust conditions for main power turbine. Pump efficiency is 85 percent.
- Pressure drop in the superheater is 10 percent of the superheater inlet pressure.
- Feedwater pump discharge is 20 percent greater than drum pressure.
- Parasitic power losses equal to 12 MW (turbine losses, generator losses, other fixed losses, auxiliary requirements for pulverizers, fans, ESP's, and miscellaneous requirements). Does not include scrubber requirements.

*An optimized cycle would probably have equal enthalpy rise through each closed feedwater heater. This cycle was selected to simplify the evaluation.

and such that the turbine output is identical to the base case output. The steam going to the flue gas reheater will have generated power in the high pressure stages of the turbine. The net effect on the turbine will be to have slightly more power generated in the high pressure stages and slightly less power generated in the low pressure stages compared to the base case.

- (4) The incremental fuel required to support the steam cycle with SGR was calculated and compared to the base case fuel requirement.
- (5) The decrease in the main condenser load and the size of the changes in steam flows within the turbine are also evaluated.

The same approach was used to determine the impact of using hot water to reheat flue gas. The hot water was extracted from the condensate stream exiting the number 3 heater (see Figure C-1). After use in the reheater the "cooled" water was mixed with the boiler feedwater exiting heater 5.

Results

Based on the above assumptions and procedures, the following results were obtained:

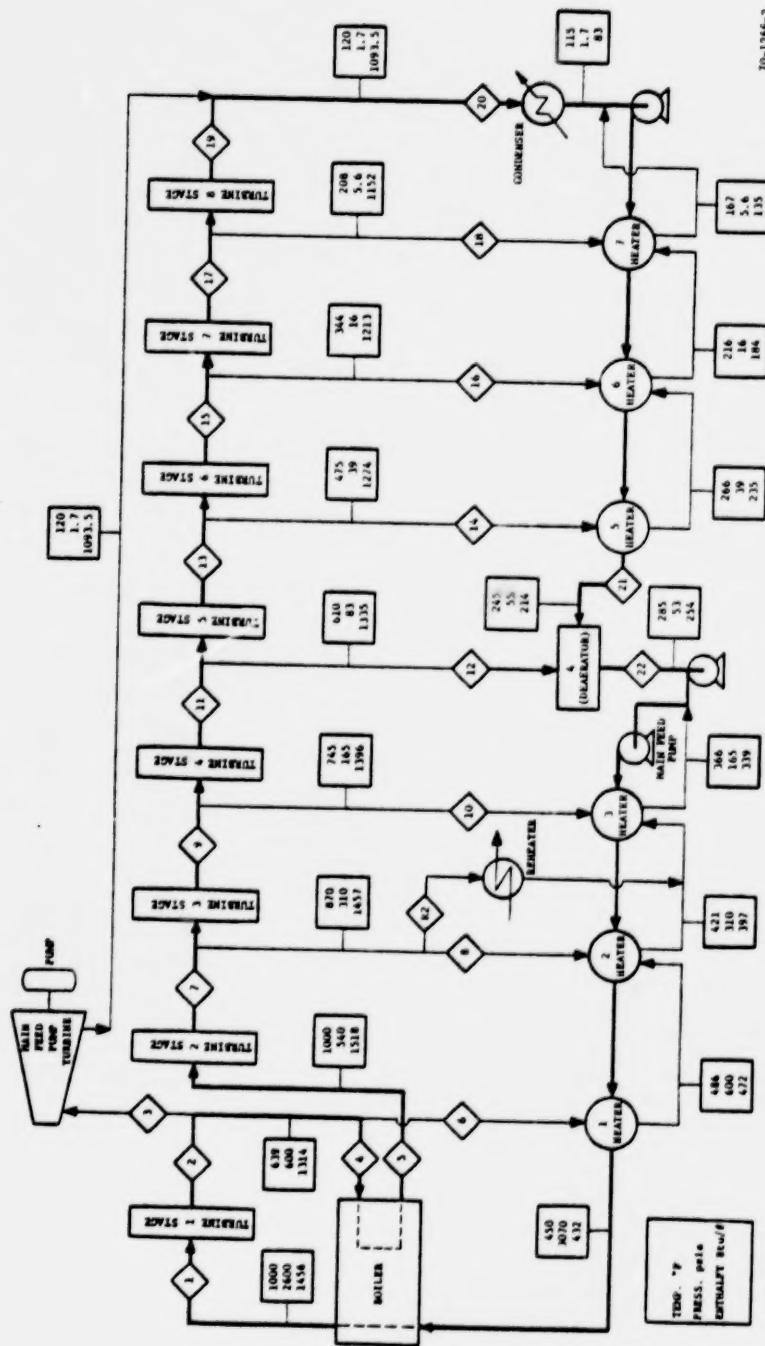
- (1) Extraction steam is considered suitable if its pressure is higher than the flue gas pressure. In case of tube failure, steam will leak into the flue gas rather than flue gas into the steam. This restriction eliminates the 5.6 psia and 1.7 psia steam levels.
- (2) Depending on the steam level selected, the amount of additional fuel required to yield 66.1×10^6 Btu/hr of stack gas reheat is approximately 0.4-1.1 percent of the total fuel consumption of the plant (5370×10^6 Btu/hr). The 0.4 percent number corresponds to the lower level steam (334°F, 16 psia), and the 1.1 percent figure refers to the highest level steam (639°F, 600 psia). The incremental heat input required by the steam cycle is always less when using extraction steam for reheat than the actual Btu's transferred to the stack gas in the reheat exchanger. This is what one would intuitively expect. If exhaust steam would suffice,

the increased heat requirement would have been zero. Had steam at high pressure throttle conditions been used, the heat input increase (to the steam cycle) would have been on a one-to-one basis compared to the heat transferred to the stack gas in the reheat exchanger. This indicates that, as the availability of energy in the steam that can be converted to work decreases, the impact of its removal from the cycle decreases.

- (3) The flow diagrams and stream flow rates that result from the use of the various applicable steam levels are presented in Figures C-2 through C-7 and Tables C-2 through C-7.
- (4) The addition of an SGR system to the base case steam cycle increases the required heat input and decreases the condenser load. These results are shown in Table C-8. The increased heat input to the steam cycle results in increasing the boiler fuel requirements; this result is shown in Table C-9.
- (5) The influence on turbine flow rates is of interest in new and especially retrofit situations. The percent change in steam mass flow rate after each turbine stage was calculated for all cases evaluated (see Table C-10). The turbine flow differences are usually less than 1 percent and always less than 2 percent. Therefore, it is realistic to expect that the design of new turbines could be adjusted to provide flue gas reheat steam in a manner similar to that described in this section. Use of extraction steam for reheat in retrofit applications may, however, result in a greater increase in fuel requirements or in a decrease in plant output.

COST OF EXTRACTION STEAM

For a new 500-MW plant the annualized cost associated with each steam level that is suitable for reheat includes a capital cost and an operating cost component. If SGR is to be used in a new 500-MW power plant, the capital cost component reflects larger capacities of certain facilities compared to the 500-MW plant with no reheat. Those facilities that could be expected to be larger are:



70-1246-2

Figure C-3. Extraction after Stage 2.

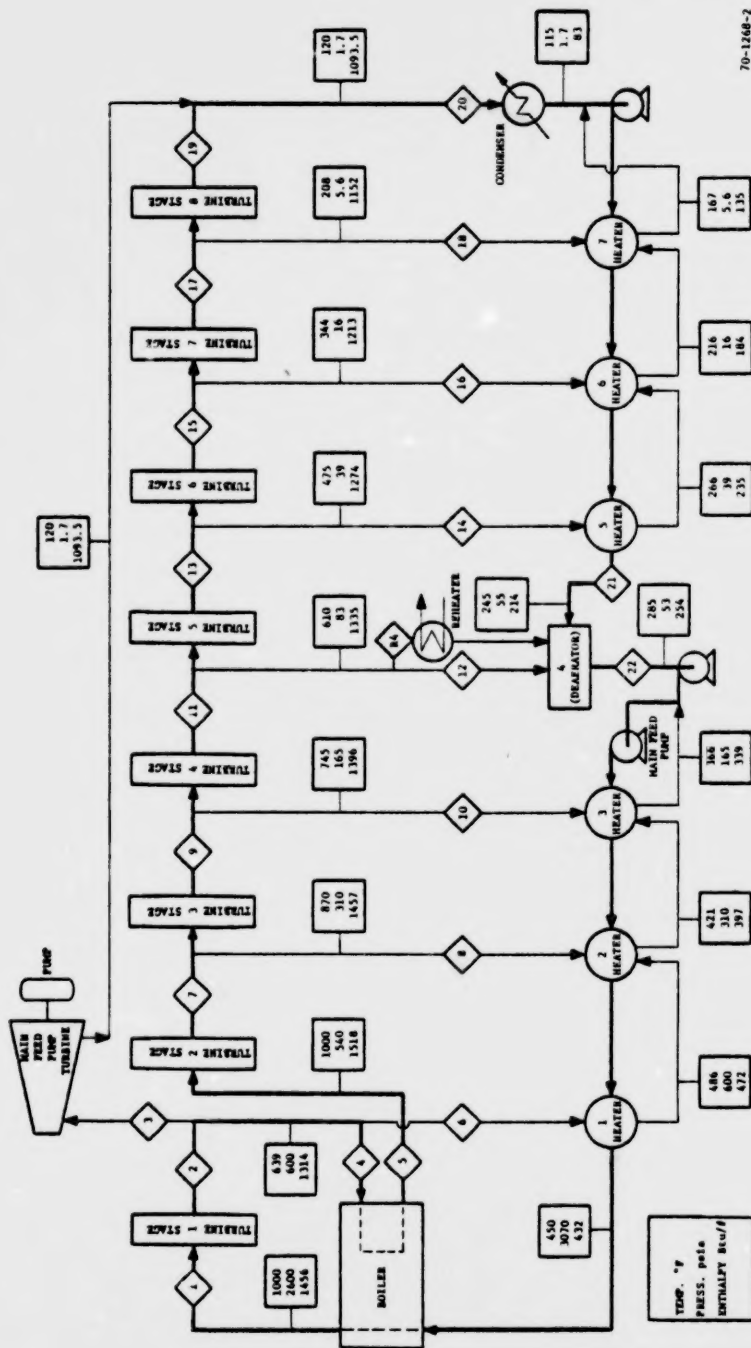
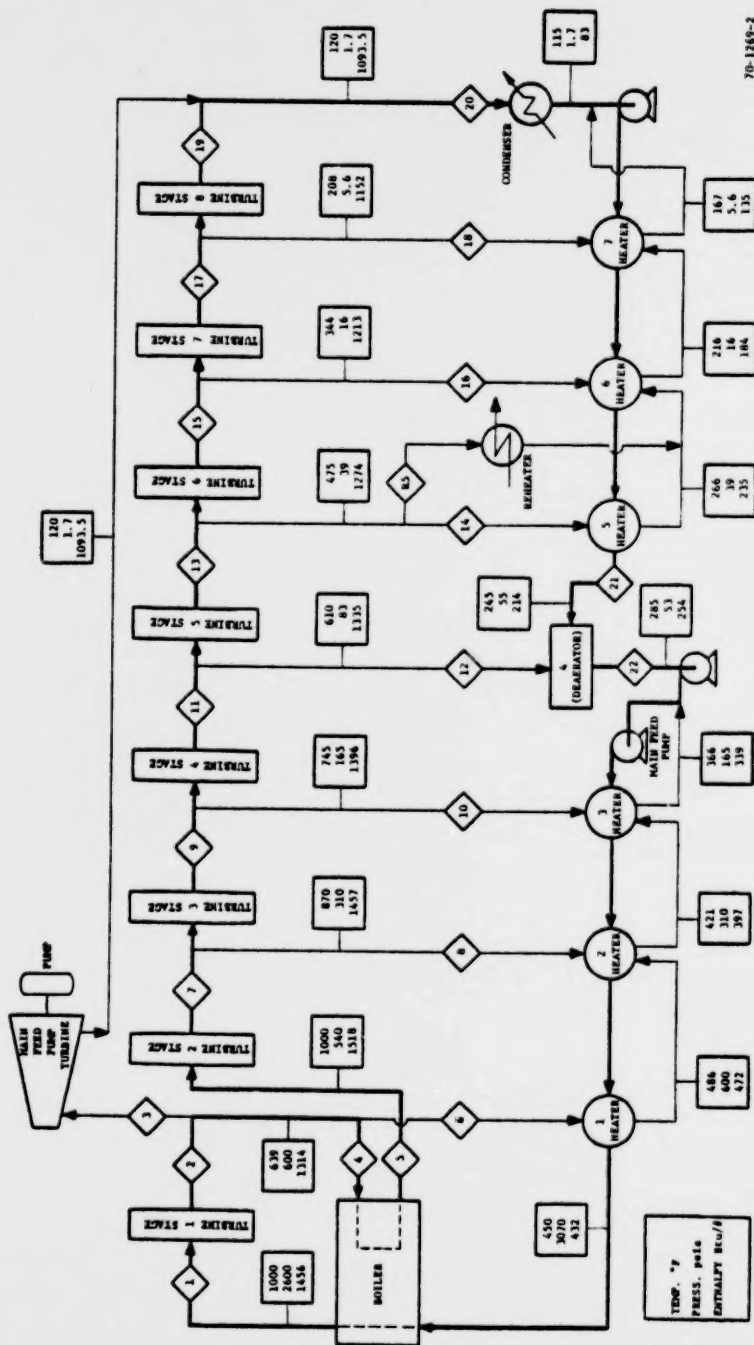
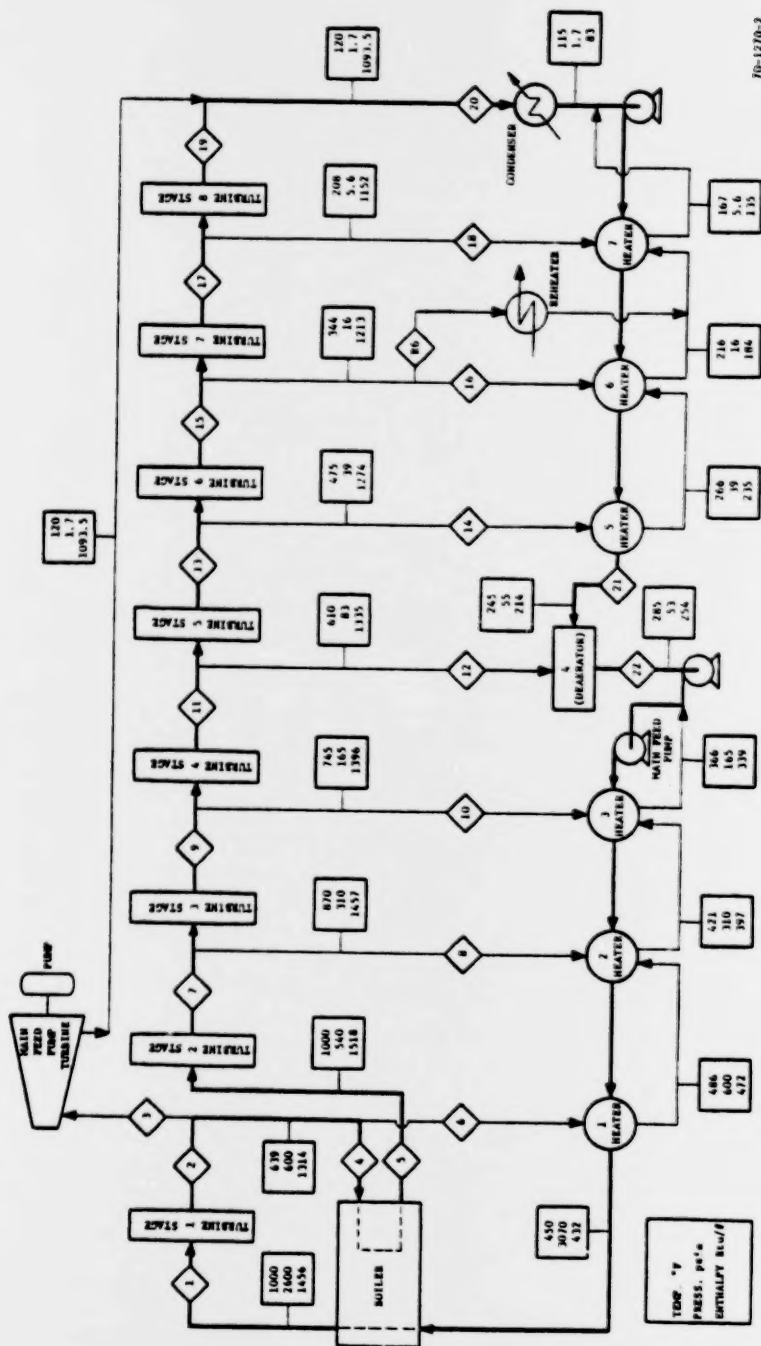


Figure C-5. Extraction after Stage 4.



70-1249-2

Figure C-6. Extraction after Stage 5.



70-1270-2

Figure C-7. Extraction after Stage 6.

TABLE C-2. FLOW RATES FOR EXTRACTION AFTER STAGE 1

Stream Number	lb/hr	Stream Number	lb/hr
1	3,835,540	13	2,889,950
2	3,835,540	14	119,630
3	205,780	15	2,770,320
4	3,367,950	16	119,630
5	3,367,950	17	2,650,690
6	183,310	18	119,630
7	3,367,950	19	2,531,060
8	181,730	20	2,736,840
9	3,186,220	21	3,095,730
10	181,730	22	3,210,270
11	3,004,490		
12	114,540	R1	78,500

TABLE C-3. FLOW RATES FOR EXTRACTION AFTER STAGE 2

Stream Number	lb/hr	Stream Number	lb/hr	Stream Number	lb/hr
1	3,819,780	11	2,999,990	21	3,091,390
2	3,819,780	12	114,380	22	3,205,770
3	205,780	13	2,885,610		
4	3,428,470	14	119,460	R2	62,360
5	3,428,470	15	2,766,150		
6	185,530	16	119,460		
7	3,428,470	17	2,646,690		
8	183,060	18	119,460		
9	3,183,050	19	2,527,230		
10	183,060	20	2,733,010		

TABLE C-4. FLOW RATES FOR EXTRACTION AFTER STAGE 3

Stream Number	lb/hr	Stream Number	lb/hr	Stream Number	lb/hr
1	3,814,400	11	2,992,150	21	3,083,830
2	3,814,400	12	114,100	22	3,197,930
3	205,780	13	2,878,050		
4	3,422,960	14	119,170	R3	62,540
5	3,422,960	15	2,758,880		
6	185,660	16	119,170		
7	3,422,960	17	2,639,710		
8	185,660	18	119,170		
9	3,237,300	19	2,520,540		
10	182,610	20	2,726,320		

TABLE C-5. FLOW RATES FOR EXTRACTION AFTER STAGE 4

Stream Number	lb/hr	Stream Number	lb/hr	Stream Number	lb/hr
1	3,808,370	11	3,045,610	21	3,076,420
2	3,808,370	12	112,020	22	3,251,390
3	205,780	13	2,870,640		
4	3,416,930	14	118,880	R4	62,950
5	3,416,930	15	2,751,760		
6	185,660	16	118,880		
7	3,416,930	17	2,632,880		
8	185,660	18	118,880		
9	3,231,270	19	2,514,000		
10	185,660	20	2,719,780		

TABLE C-6. FLOW RATES FOR EXTRACTION AFTER STAGE 5

Stream Number	lb/hr	Stream Number	lb/hr	Stream Number	lb/hr
1	3,802,080	11	3,040,310	21	2,131,460
2	3,802,080	12	114,630	22	3,246,090
3	205,780	13	2,295,680		
4	3,410,970	14	118,550	R5	63,620
5	3,410,970	15	2,743,510		
6	185,330	16	118,550		
7	3,410,970	17	2,624,960		
8	185,330	18	118,550		
9	3,225,640	19	2,506,410		
10	185,330	20	2,712,190		

TABLE C-7. FLOW RATES FOR EXTRACTION AFTER STAGE 6

Stream Number	lb/hr	Stream Number	lb/hr	Stream Number	lb/hr
1	3,795,590	11	3,034,690	21	3,124,860
2	3,795,590	12	115,610	22	3,240,470
3	205,780	13	2,919,080		
4	3,404,770	14	120,020	R6	64,240
5	3,404,770	15	2,799,060		
6	185,040	16	118,200		
7	3,404,770	17	2,616,620		
8	185,040	18	118,200		
9	3,219,730	19	2,498,420		
10	185,040	20	2,704,200		

TABLE C-8. IMPACT OF UTILIZING VARIOUS STEAM LEVELS FOR SCR ON BASE CASE STEAM CYCLE

After Stage	Extraction Conditions for SCR			Energy Change ¹ , 10 ⁶ Btu/hr		Steam Cycle Heat Input Increase ² (Fraction of Reheat Duty)
	Temp., °F	Pressure, psia	Saturation Temp., °F	Flow, lb/hr	Increase in Steam Cycle Energy Input Decrease in Condenser Load	
6	344	16	216	64,240	17.6	48.5
5	475	39	266	63,620	25.7	40.4
4	610	83	315	62,950	33.4	32.7
3	745	165	366	62,540	40.0	26.1
2	870	310	421	62,360	46.8	19.3
1	639	600	486	78,500	50.6	15.5
						0.266
						.389
						.505
						.605
						.708
						.766

¹Sum (absolute value) of steam cycle increase and condenser decrease equals SGR heat requirements (66.1 x 10⁶ Btu/hr).

²Example: For extraction after turbine stage 6, fraction of reheat duty = (17.6 x 10⁶ Btu/hr)/ (66.1 x 10⁶ Btu/hr) = 0.266.

TABLE C-9. IMPACT OF UTILIZING VARIOUS STEAM LEVELS FOR SCR ON BASE CASE FUEL REQUIREMENTS

Reheat Steam Taken After Turbine Stage	Increase in Fuel Requirements ¹ , 10 ⁶ Btu/hr	Fraction of Base Case Plant Fuel Requirement ²
6	20.7	0.0039
5	30.2	.0056
4	39.3	.0073
3	47.1	.0088
2	55.1	.0103
1	59.5	.0111

¹Over base case fuel requirements. This is the fuel (to boiler) makeup required to supply 66.1 x 10⁶ Btu/hr of reheat steam.

²Base case fuel requirement is 5370 x 10⁶ Btu/hr.

TABLE C-10. TURBINE FLOW CHANGES

After Turbine Stage	Base Case Flows, 10^3 lb/hr	Main Steam Flow (Percent Change From Base Case Flows)				
		6	5	4	3	2 1
1	3,781	0.37	0.56	0.71	0.87	1.01 1.42
2	3,391	0.38	0.59	0.74	0.91	1.09 -0.71
3	3,206	0.41	0.59	0.78	0.97	-0.72 -0.63
4	3,022	0.40	0.60	0.76	-0.99	-0.76 -0.60
5	2,907	0.41	0.62	-1.27	-1.00	-0.76 -0.62
6	2,786	0.47	-1.54	-1.26	-1.00	-0.72 -0.57
7	2,666	-1.88	-1.57	-1.27	-1.01	-0.75 -0.60
8	2,546	-1.89	-1.57	-1.26	-1.02	-0.75 -0.59

Example: If the flue gas reheat steam is extracted after turbine stage 6, then the following analysis can be developed (using data from Tables C-1 and C-7).

Stream Number Figure C-1	Location (After Turbine Stage)	Base Case Flow Rate From Table C-1 (10^3 lb/hr)	Case Adjusted for Reheat From Table C-7 (10^3 lb/hr)	Percent Change in Flow of Adjusted Case Compared to Base Case
2	1	3,781	3,795	0.37
7	2	3,391	3,404	0.38
9	3	3,206	3,219	0.41
11	4	3,022	3,034	0.40
13	5	2,907	2,919	0.41
15	6	2,786	2,799	0.47
17	7	2,666	2,616	-1.88
19	8	2,546	2,498	-1.89

- (1) The coal preparation and handling equipment
- (2) The boiler and associated equipment
- (3) FGD system and solid waste disposal area
- (4) Plant stack and duct work
- (5) Larger fans to overcome system ΔP for air and stack gases associated with the added fuel firing rate.

The operating cost component consists of fuel and operating and maintenance costs. These components as well as the annualized costs of the various steam levels are summarized in Table C-11 and are developed below.

Capital Component of Steam Cost

The bases for developing the capital component of the steam cost are presented below:

Total capital requirement for 500-MW power plant = \$800/kW (mid-1978 dollars)*

Fraction of plant capital cost that will increase in proportion to the increase in fuel firing because of the addition of reheat (Derived from information reported by Bechtel)³³ = 265 percent

Using the bases presented above and the incremental fuel required for using the various levels of steam for reheat, the capital investment required for the production of reheat steam in the quantities required for this example problem is estimated and shown in Table C-11.

* Includes installed equipment cost, contingency, allowance for funds used during construction, and other indirect costs.

TABLE C-11. COSTS OF VARIOUS LEVELS OF STEAM (NEW 500-MW PLANT)
TO PROVIDE 66×10^6 BTU/HR OF REHEAT

Extraction Steam for Reheat			Additional Fuel Requirement ^a		Capital ^c Investment (10 ³ \$)	Operating Costs ^d (10 ³ \$/yr)	Annual ^e Revenue Required (10 ³ \$/yr)	Steam Costs (1978 \$)	
Flow Rate (10 ³ lb/hr)	Steam (psia)	Temp. (°F)	10 ⁶ Btu/hr ^a	Fraction of ^b Base Case				\$/10 ⁶ Btu ^f	Saturated ^h \$/1000 lb
64.2	16	344	20.7	.0019	1010	236	373	0.81	0.78
63.6	39	475	30.2	.0026	1460	345	542	1.17	1.10
63.0	83	610	39.3	.0073	1900	468	705	1.52	1.37
62.5	165	745	47.1	.0088	2290	517	846	1.83	1.57
62.4	310	870	55.1	.0103	2680	629	991	2.14	1.73
78.5	600	639	59.5	.0111	2890	679	1069	2.31	1.95
534.0	Hot Water	366	49.0	.0093	2420	565	891	1.93	1.69

^aThis is the additional fuel required to provide 66.1×10^6 Btu/hr of reheat steam at the stated quality.
^bThe plant base case fuel consumption is 5370×10^6 Btu/hr.
^cThis reflects increased capacity of some plant equipment as a result of adding reheat to plant (fraction of base case fuel requirement $\times$ base case total plant capital investment $\times 0.65$).
^dThis reflects the incremental fuel and plant O&M costs [$(\$1.00/10^6 \text{ Btu} + \$0.63/10^6 \text{ Btu}) \times \text{additional annual fuel requirement}$].
^eAnnual revenue required to generate additional steam for 66.1×10^6 Btu/hr of reheat.
^fUnit cost of steam is based on annualized cost of plant (annual revenue requirement divided by annual steam flow).
^hCost of saturated steam at same pressure using desuperheater.

Operating Cost Component of Steam Cost

The operating cost component of the steam cost reflects the incremental fuel requirements and O&M charges. The bases for the development of these operating cost components are presented below.

Fuel cost = $\$1/10^6$ Btu

Operating and maintenance costs* for 500 MW plant = 7 mills/kwh
= $\$0.63/10^6$ Btu of
fuel input

Using these assumptions, the calculated incremental fuel input required for producing reheat steam, and the calculated fractional increase in plant capacity, the operating cost component of the steam costs was determined.** This component is shown in Table C-11.

Annual Revenue Requirement

The annual revenue requirement for each steam level was developed by combining the annual operating cost component and the annual cost associated with capital investment. The expression and bases for developing the annual revenue requirement follow, while the costs are presented in Table C-11.

A utility financing method was chosen as the basis for estimating annual costs of owning and operating reheat equipment. Presented below is a derivation of the equations used:

(1) Nomenclature and assumptions:

Total federal and state taxes = 50 percent

C = total capital investment required

* Includes O&M for boiler, turbine, and all auxiliaries (including FGD system and solid waste disposal).

**A capacity factor of 7000 hr/yr was selected.

N = annual operating cost = heating media cost +
O&M cost

d = fraction debt

i = interest rate for borrowing capital

r = percent return on equity

p = percent return on rate base

m = equipment life in years

TRR = total revenue requirement over the life of the equipment
Depreciation schedule is straight line.

- (2) Calculate rate base in n^{th} year

Depreciable investment = C

Accrued depreciation at mid-point of n^{th} year = $(1/m)(n-0.5)C$

Rate base = $C - (1/m)(n-0.5)C = C[1 - (1/m)(n-0.5)]$

- (3) Calculate percent return on rate base

$p = (d)i + (1-d)r$

- (4) Calculate cash flows in n^{th} year

Return on rate base = $0.01 p C[1 - (1/m)(n-0.5)]$

Return on equity* = $0.01 r C[1-d][1 - (1/m)(n-0.5)]$

Taxes* = $0.01 r C[1-d][1 - (1/m)(n-0.5)]$

Depreciation = C/m

Annual revenue requirement** = $N + \text{return on rate base} + \text{taxes} + \text{depreciation}$

= $N + C/m + 0.01 C [p + r(1-d)][1 - (1/m)(n-0.5)]$

*Return on equity and state and federal taxes are identical when the tax rate is 50%.

**Return on equity (ROE) is included in return on rate base calculation. ROE was calculated separately so that state and federal taxes could be calculated.

- (5) Calculate total revenue requirement over the life of the project (assuming no operating cost escalation)

$$TRR = mN + C + 0.01 C [p + r(1-d)] \left[\sum_{n=1}^m \left(1 - \frac{n-0.5}{m} \right) \right]$$

$$\sum_{n=1}^m \left(1 - \frac{n-0.5}{m} \right) = \frac{m}{2}$$

$$TRR = mN + C + 0.005 m C [p + r(1-d)]$$

- (6) Average annual revenue requirement = $ARR = TRR/m$

$$ARR = N + C/m + 0.005 C [p + r(1-d)]$$

- (7) As a basis for this study:

a) All investments and operating costs are expressed in terms of 1978 dollars.

b) Operating costs (N) are not escalated.

c) $d = 0.50$

d) $r = 14$

e) $i = 10$

f) Therefore $p = 12$

$$TRR = mN + C + 0.095m C$$

$$ARR = N + C/m + 0.095 C$$

g) The Average Annual Revenue Requirement will be used to make economic comparisons when expected equipment life is known.

Cost of Various Steam Levels

The costs developed for various steam levels from the "hypothetical" steam cycle are presented in Table C-11. Although it is recognized that steam costs are very site specific, the relative costs (trends) of the steam levels are expected to be similar for other steam cycles. Factors that will

influence steam costs are the design of the steam cycle, fuel costs, fuel quality, capital cost of the power plant, and turbine design, etc. The steam costs shown in Table C-11 are considered to be the costs of reheat steam that would be obtainable from new 500-MW power plants.*

Costs for superheated steam (at extraction steam conditions) and saturated steam (superheated steam is desuperheated by spraying condensate into the steam) are presented in Table C-11. Reheat users responding to the OMB-approved survey stated that the use of saturated steam (instead of superheated steam) offers reliability advantages.

Costs of steam from existing power plants for retrofit FGD/SGR or SGR systems are much more difficult to quantify. The value of steam, at a given quality, could range from:

- (1) the marginal cost (fuel only) of producing that steam to
- (2) the value of the lost power production resulting from utilizing the steam in a reheater.

Also sufficient quantities of steam for reheat purposes may not be available for extraction on existing turbines.

Any of the reheat cases developed in this study could be used to estimate the cost of SGR on retrofit installations. The cost of the steam is the unknown quantity. Available boiler fuel capacity, turbine ability to provide sufficient steam quantities, resulting turbine output and heat rate after extraction of reheat steam, and fuel value would have to be evaluated to determine a steam cost.

*These are the steam qualities that are evaluated in Chapter 7 to develop SGR costs. It is recognized that these steams do not absolutely define the availability of steam for SGR at any power plant. However, the relative costs are expected to be reasonable and the use of different quality steams would not be expected to change the general results and trends noted in this study.

APPENDIX D

EQUIPMENT SIZING BASES
(REHEAT EXCHANGERS, FANS, STACKS)

APPENDIX D

EQUIPMENT SIZING BASES (REHEAT EXCHANGERS, FANS, STACKS)

INTRODUCTION

The calculational procedures and bases for sizing the equipment required for various reheat configurations are presented in this appendix.

BASES

A 500-MW plant was selected for the base case in all reheat economic calculations. The base coal and scrubbed flue gas composition for this plant is presented in Table D-1 along with the scrubber exit gas compositions that result from different primary fan placements and reheat configurations (see Figure D-1). The heat rate of the plant is 9000 Btu/kWh.

HEAT EXCHANGER SURFACE AREA REQUIREMENTS

For the inline, indirect hot air, and exit gas recirculation reheat schemes, heat exchangers are required. In this report, capital investments for these reheat schemes are calculated on the bases of estimated exchanger surface area. Exchanger surface area will be a function of steam quality, exchanger gas-side pressure drop, temperature profiles, and tube orientation and dimensions, etc. An accurate estimate of the factors affecting the area is desired in order to develop meaningful cost estimates.

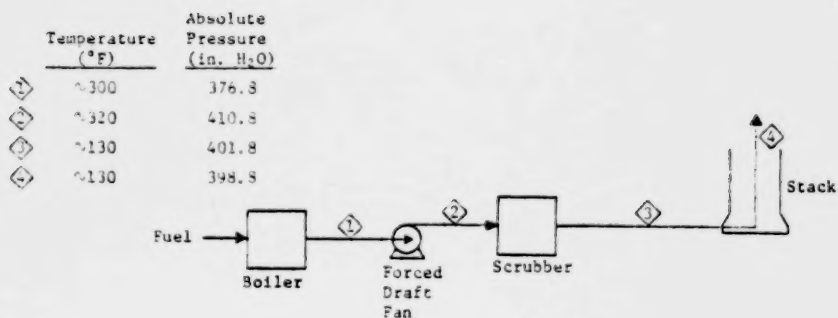
To estimate the exchanger surface area required, the quantity of heat that is needed to achieve a given level of reheat must be determined. This heat requirement (at steady-state) can be calculated with Equation D-1 (a nomenclature section is presented at the end of Appendix D). Equation D-1

TABLE D-1. PLANT CHARACTERISTICS AND PRIMARY FAN CONFIGURATIONS

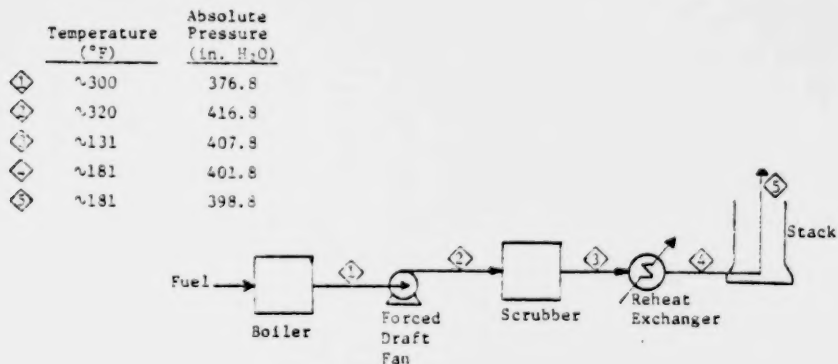
Power Plant Basics, Fuel and Flue Gas Compositions		
Power Plant Characteristics	Coal Composition	
	Component	Weight Percent
• New, 500-MW	C	57.56
• 9,000 Btu/lb Heat Rate	H	4.14
• Flue gas temperature entering scrubber is 300°F	N	1.29
	O	7.00
	S	3.12
	Cl	0.15
	H ₂ O	10.74
	Ash	16.00
	Heat Content	10,500 Btu/lb
Flue Gas Composition Entering Scrubber		
Component	Volume Percent	Lb/hr
N ₂	73.76	3,450,000
O ₂	4.83	258,200
CO ₂ *	12.31	904,200
SO ₂	0.24	25,130
SO ₃	0.0024	317
NO _x	0.06	3,022
HCl	0.01	661
H ₂ O	8.79	264,500
		4,906,030
	*Includes a small amount of CO	

Primary Fan Arrangement and Equipment Pressure Drop Assumptions		
Impact of Fan Location on Flue Gas Composition and Adiabatic Saturation Temperature		
Fan Configuration	Forced Draft 40% _{DP} (Figure D-1a)	Forced Draft 40% _{DP} (Figure D-1b)
Saturation Temperature, (°F)	130	131
Normalized Flue Gas Composition		
Component	Lb/hr	Lb/hr
N ₂	3,471,000	3,471,000
O ₂	259,700	259,700
CO ₂	909,600	909,600
H ₂ O	498,400	501,600
	5,139,600	5,142,000
Note: The flue gas specific heat of each configuration was taken as 0.26 Btu/lb-°F.		

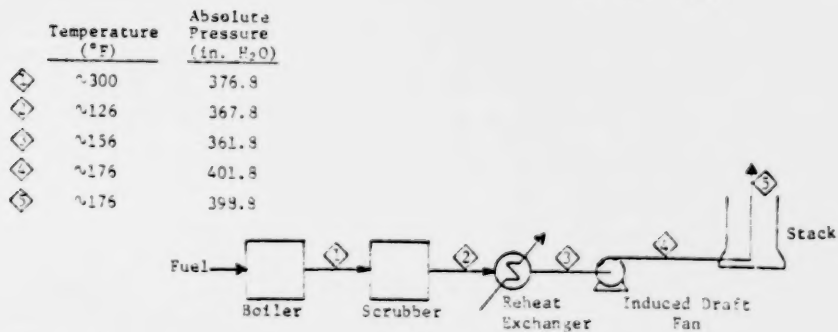
Equipment Pressure Drop		
• Boiler ΔP = 22 in. H ₂ O		
• Scrubber ΔP = 9 in. H ₂ O		
• Reheat Exchanger ΔP = 6 in. H ₂ O		
• Stack, duct work ΔP = 3 in. H ₂ O		



(a) Forced draft FGD system with no reheat (overall pressure drop = 34 in. H₂O)



(b) Forced draft FGD system with inline reheat (overall pressure drop = 40 in. H₂O)



(c) Induced draft FGD system with inline reheat (overall pressure drop = 40 in. H₂O)

Figure D-1. Schematics of FGD systems with different primary fan positions.

reflects the assumptions that no liquid is entrained in the flue gas and no heat is lost from the flue gas (through the walls of the duct and stack):

$$Q = \dot{m}_{FG} C_{FG} \Delta t_{EB} \quad (D-1)$$

In this expression, Δt_{EB} represents the difference between the stack exit and scrubber exit temperatures or the desired level of reheat.

The amount of steam required to supply this energy is obtained next. Using dry, saturated steam and condensing it in the reheater, the required steam flow ($\dot{m}_s$) is:

$$\dot{m}_s = Q/\lambda \quad (D-2)$$

where λ is the latent heat of vaporization of the steam.

The reheaters considered in this study have the gas flow outside and perpendicular to the tubes. The heating medium, steam or water, will flow inside the tubes. Since major economic factors of reheater design will be surface area and gas-side pressure drop, a correlation relating these two variables is developed.

The pressure drop is best correlated in dimensionless form. The pressure drop is calculated as the number of velocity heads lost per column of tubes. Equation D-3 does this.

$$\Delta P = (4fN)(v^2/2g) \quad (D-3)$$

The friction factor, f , is normally correlated as a function of the Reynolds number.

$$\frac{f}{2} = \alpha_1 \text{Re}^{-n_1} \quad (\text{D-4a})$$

$$= j_M \quad (\text{D-4b})$$

The standard equation for heat transfer is given in Equation D-5.

$$Q = U A_H \Delta t_H \quad (\text{D-5})$$

where A_H is the exchanger surface area, U is the overall heat transfer coefficient, and Δt_H is the logarithmic mean temperature difference (Figure D-4).

Equation D-6 is useful if one thermal resistance is much smaller than the others. This is the case with condensing steam and turbulent hot water. The inside coefficient is much higher than the gas-side coefficient. As a result, the gas-side coefficient is a good approximation of the overall coefficient and equation D-5 becomes:

$$Q = h A_H \Delta t_H \quad (\text{D-6})$$

where h is the gas-side heat transfer coefficient and A_H is the total heat transfer surface area (surface area on outside of tubes).

Heat transfer coefficients are also best correlated with dimensionless groups. A frequently used form is Equation D-7.

$$\left(\frac{h}{c_{pV}} \right) \text{Pr}^{2/3} = j_H \quad (\text{D-7})$$

The "j" factor for heat transfer is normally assumed to be a function of the Reynolds number.

$$j_H = \alpha_2 \text{Re}^{-n_2} \quad (\text{D-8})$$

In many cases, including gaseous flow outside of tubes, the j -factors for heat and momentum transfer are considered equal. This is known as the Colburn j -factor analogy. It can provide an estimation method for heat transfer or pressure drop if only one is known. In this study the pressure drop across the exchanger will be estimated, allowing calculation of the heat transfer coefficient. The tube bundle layout for this analysis is shown in Figures D-2 and D-3. The Reynolds number is based on the tube diameter and the maximum actual velocity, v , that occurs in the bundle and is determined from equation D-9.

$$Re = Dv\rho/\mu \quad (D-9)$$

For the equilateral triangular pitch used in this study, this maximum velocity will occur in the space, S-D, between tubes perpendicular to the flow as shown in Figure D-2.

The pressure drop equations, D-3 and D-4, may be combined to yield:

$$\Delta P = (8j_M N)(v^2/2g) \quad (D-10)$$

The j -factor is already a function of Reynolds number, Re , only. The velocity term may be converted to Re by multiplying and dividing by $(D\rho/\mu)^2$.

$$\Delta P = \frac{8N}{2g} (\alpha_1 Re^{-n_1}) Re^2 \left(\frac{\mu}{D\rho} \right)^2 \quad (D-11)$$

This equation may be solved for Re :

$$Re = \left[\frac{g\Delta P}{4N\alpha_1} \left(\frac{D\rho}{\mu} \right)^2 \right]^{\frac{1}{2-n_1}} \quad (D-12)$$

The Reynolds number in Equation D-12 may be substituted into the heat transfer j -factor equation. Rearrangement of Equation D-7 and use of

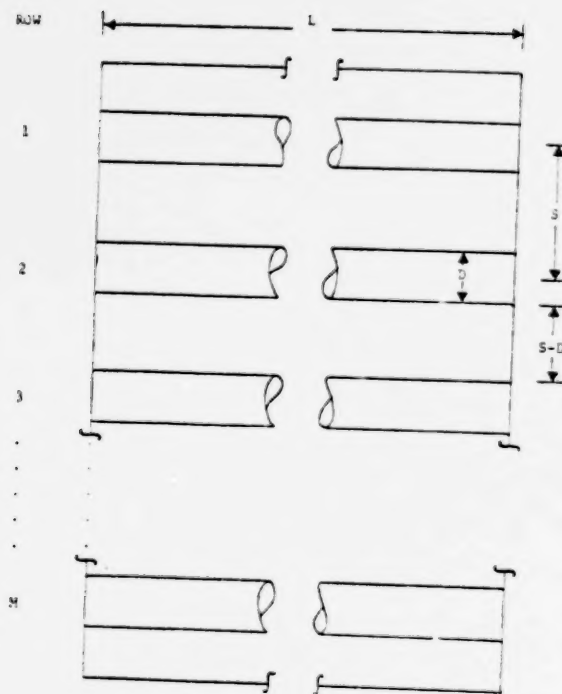


Figure D-2. Front view of first column of reheater tubes.

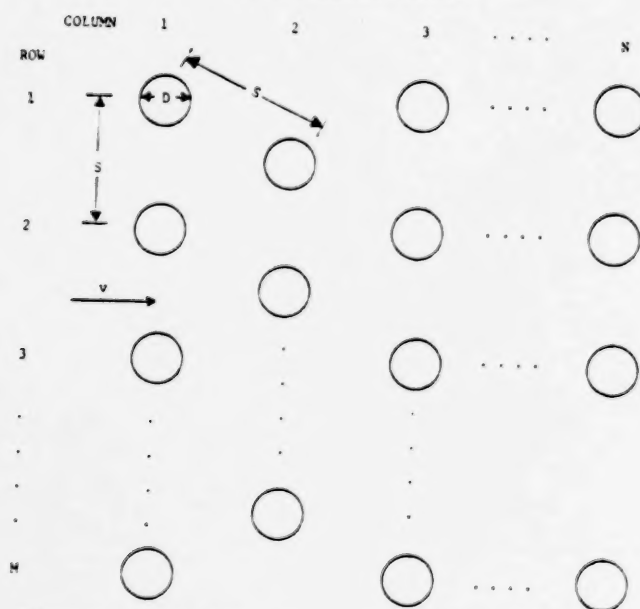


Figure D-3. Side view of reheater tubes.

Equations D-8 and D-12 results in the heat transfer coefficient given by Equation D-13b.

$$h = \frac{C_{FG}^{ov}}{Pr^{2/3}} j_H \quad (D-13a)$$

$$= \frac{C_{FG}^{ov}}{Pr^{2/3}} \alpha_2 \left[\frac{g\Delta P}{4N\alpha_1} \left(\frac{D_0}{L} \right)^2 \right]^{\frac{-n_2}{2-n_1}} \quad (D-13b)$$

Steady-state energy and mass balances must be made to solve these equations. The mass balance relates the total flue gas flow to tube geometry and velocity as shown in the following expressions:

$$\dot{m}_{FG} = ov (S-D)LM \quad (D-14a)$$

$$= ov (S/D-1)DLM \quad (D-14b)$$

The heat balance requires that the heat added to the flue gas as calculated by the transfer mechanism is equal to the heat added as calculated by an energy balance. The schematic in Figure D-4 describes the terms to be used. Equation D-6 defines the heat required by the heat transfer mechanism, and substitution of the variables that define the heat transfer area into this expression yields:

$$Q = h \pi D L M N \Delta t_H \quad (D-15)$$

where $\pi D L$ is the surface area of one tube and $M N$ is the total number of tubes.

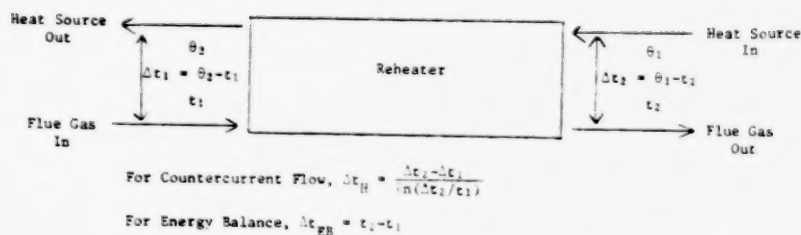


Figure D-4. Schematic of inline reheater for energy balance considerations.

The steady-state energy balance term is written in terms of the velocity using Equations D-1 and D-14.

$$Q = \dot{m}_{FG} C_{FG} \Delta t_{EB} \quad (D-16a)$$

$$= \rho v (S/D-1) DLMC_{FG} \Delta t_{EB} \quad (D-16b)$$

Equations D-15 and D-16b may be equated:

$$h \pi D L M N \Delta t_H = \rho v (S/D-1) DLMC_{FG} \Delta t_{EB} \quad (D-17a)$$

$$h \pi N \Delta t_H = \rho v (S/D-1) C_{FG} \Delta t_{EB} \quad (D-17b)$$

The value for h from Equation D-13b may be substituted into equation D-17b resulting in:

$$\frac{C_{FG} \rho v}{Pr^{2/3}} \alpha_2 \left[\frac{g \Delta P}{4 N \alpha_1} \left(\frac{D_0}{u} \right)^2 \right]^{\frac{-n_2}{2-n_1}} \pi N \Delta t_H = \rho v (S/D-1) C_{FG} \Delta t_{EB} \quad (D-18a)$$

$$\frac{N \pi \alpha_2}{Pr^{2/3}} \left[\frac{g \Delta P}{4 N \alpha_1} \left(\frac{D_0}{u} \right)^2 \right]^{\frac{-n_2}{2-n_1}} \Delta t_H = (S/D-1) \Delta t_{EB} \quad (D-18b)$$

If the pressure drop (ΔP) is assumed, the number of columns, N , becomes the only unknown in Equation D-18b.

$$N = \left\{ \frac{(S/D-1) Pr^{2/3}}{\pi \alpha_2} \left(\frac{\Delta t_{EB}}{\Delta t_H} \right) \left[\frac{g \Delta P}{4 \alpha_1} \left(\frac{D_o}{\mu} \right)^2 \right]^{\frac{n_2}{2-n_1}} \right\}^{\frac{2-n_1}{2+(n_2-n_1)}} \quad (D-19a)$$

$$= \left[\frac{(S/D-1) Pr^{2/3}}{\pi \alpha_2} \left(\frac{\Delta t_{EB}}{\Delta t_H} \right) \right]^{\frac{2-n_1}{2+(n_2-n_1)}} \left[\frac{g \Delta P}{4 \alpha_1} \left(\frac{D_o}{\mu} \right)^2 \right]^{\frac{n_2}{2+(n_2-n_1)}} \quad (D-19b)$$

The other variables and parameters in this expression may be determined from the physical properties of the flue gas or exchanger. The Reynolds number is calculated from Equation D-12 now that N is known. The velocity, v , can be calculated from the definition of Re (Equation D-9).

$$v = Re / (D_o / \mu) \quad (D-20)$$

The total tube length per column, LM , for the number of tubes in a column, may be solved from Equation D-21, which was derived from the rearrangement of Equation D-14. The parameters, DLM ($S/D-1$) collectively represent the cross sectional area available for the flow of flue gas.

$$LM = \frac{\dot{m}_{FG}}{\rho v D(S/D-1)} \quad (D-21)$$

A reasonable value for L is selected so that M may be calculated.

The total surface area required for heat transfer can now be obtained with the following expression:

$$A_H = NLM\pi D \quad (D-22)$$

To compensate for possible fouling, 25 percent additional area is added to the areas calculated for the exchanger in the inline and exit gas

recirculation reheat configurations. A safety factor of 10 percent was used for the indirect hot air configuration.

The heat transfer coefficient is also of interest. It can now be calculated using Equations D-7 and D-8.

$$h = \frac{C_{FG} \rho v}{Pr^{2/3}} \alpha_2 Re^{-n_2} \quad (D-23)$$

As an example, the area for the inline exchanger using 600 psia, dry saturated steam with a 6-inch (water) pressure drop is calculated (see Table E-1, Appendix E). In this example, the values of the flue gas physical properties that are used are determined at the average temperature of the flue gas.

Assumptions:

- (1) Flue gas temperature (entering exchanger) = 131°F
- (2) Flue gas temperature (exiting exchanger) = 181°F
- (3) 1-inch O.D. tubes for the reheat exchanger
- (4) 3-inch center-to-center equilateral tube spacing
- (5) $Pr = \frac{C_{FG} \mu}{K}$
 $= (.26)(1.34 \times 10^{-5}) / (4.44 \times 10^{-6}) = 0.78$
- (6) Exchanger pressure drop (ΔP) = 6" H₂O = 495 feet of gas
 (H₂O considered to be 62.4 lb_m/ft³ for all cases).
- (7) $\rho = MW \times \bar{P} / R \times T$ = average density of flue gas
 $= 28.5(14.6) / 10.73(460 + 156) = .0629 \text{ lb/ft}^3$
- (8) $\Delta t_{EB} = (181 - 131)^\circ\text{F} = 50^\circ\text{F}$
- (9) $\Delta t_H = (486 - 131)^\circ\text{F} - (486 - 181)^\circ\text{F} / \ln \frac{(486 - 131)^\circ\text{F}}{(486 - 181)^\circ\text{F}} = 329^\circ\text{F}$
- (10) $n_1 = .247$ $n_2 = .40$
 $\alpha_1 = .36$ $\alpha_2 = .33$ (Ref. 34)
- (11) $g = 32.2 \text{ ft/sec}^2$

First the amount of energy required to heat the flue gas 50°F will be obtained for a 500-MW plant (assuming no heat losses or mist carry-over).

$$\begin{aligned}
 Q &= \dot{m}_{fg} C_{FG}(\Delta t) & (D-1) \\
 &= 5,140,000 \frac{\text{lb}}{\text{hr}} \times .26 \frac{\text{Btu}}{\text{lb-}^\circ\text{F}} \times (181-131)^\circ\text{F} \\
 &= 66.8 \times 10^6 \text{ Btu/hr}
 \end{aligned}$$

The amount of steam required to achieve the specified heat duty is obtained next.

$$\begin{aligned}
 \dot{m}_s &= Q/\lambda & (D-2) \\
 &= (66.8 \times 10^6 \text{ Btu/hr})/(732 \text{ Btu/lb}) \\
 &= 91,300 \text{ lb/hr}
 \end{aligned}$$

The number of tube columns can now be calculated. Putting the above parameters into Equation D-19b yields:

$$\begin{aligned}
 N &= \left[\frac{(3-1)}{\pi} \frac{(.78)}{.33} \right]^{2/3} \left(\frac{50}{329} \right)^{\frac{2-.247}{2+ (.4-.247)}} \left[\frac{32.2(495)}{4(0.36)} \left(\frac{1/12(.0629)}{1.34 \times 10^{-5}} \right)^2 \right]^{\frac{.4}{2+ (.4-.247)}} \\
 &= 16.8 & (D-19b)
 \end{aligned}$$

The Reynolds number through the exchanger may be obtained using Equation D-12.

$$\begin{aligned}
 \text{Re} &= \left[\frac{g\Delta P}{4N\alpha_1} \left(\frac{DC}{\mu} \right)^2 \right]^{1/(2-n_1)} & (D-12) \\
 &= \left[\frac{32.2(495)}{4(16.8)(.36)} \left(\frac{1/12(.0629)}{1.34 \times 10^{-5}} \right)^2 \right]^{\frac{1}{2-.247}} \\
 &= 36,700
 \end{aligned}$$

The flue gas velocity is obtained with the following expression:

$$\begin{aligned}
 v &= Re / (D \rho / \mu) & (D-20) \\
 &= 36,700 \left(\frac{1/12 (.0629)}{1.34 \times 10^{-5}} \right) \\
 &= 94 \text{ ft/sec}
 \end{aligned}$$

The total tube length per column, LM, can now be calculated. M is the number of rows in each column, L is their length.

$$\begin{aligned}
 LM &= \frac{\dot{m}_{fg}}{\rho v D (S/D - 1)} & (D-21) \\
 &= \frac{5,140,000/3600}{.0629 (94) \left(\frac{1}{12}\right) (3-1)} \\
 &= 1450 \text{ ft}
 \end{aligned}$$

Finally, the total exchanger surface area is calculated.

$$\begin{aligned}
 A &= L M N \pi D & (D-22) \\
 &= (1450) (16.8) (3.14) \left(\frac{1}{12}\right) \\
 &= 6400 \text{ ft}^2
 \end{aligned}$$

Heat exchanger designs normally include a fouling factor which reduces the overall heat transfer coefficient and increases the required area. Another method to account for fouling simply involves using a greater area. Based on this technique, a 25 percent safety factor was added to the heat transfer area resulting in an area of 8,000 ft². Calculation of the outside heat transfer coefficient is also of interest. The inside coefficient is neglected since it is very high for a condensing fluid, while the thermal resistance of the tube material is neglected as the tube wall is thin and its thermal conductivity is high.

$$h = 3600 C_{FG}^{0.0012} Re^{-0.4} / Pr^{2/3} \quad (D-23)$$

$$= 3600 (.26)(.0629)(94)(.33)(36,700)^{-0.4} / (.78)^{2/3}$$

$$= 32 \text{ Btu/hr-ft}^2\text{-F}^\circ \text{ (before providing fouling safety factors)}$$

The results of the above sample calculation are as follows:

- (1) Flue gas temperature increase = 50°F
- (2) Heat input required = 66.8×10^6 Btu/hr
- (3) Flue gas flow rate = 5.14×10^6 lb/hr
- (4) Required steam flow rate = 91,000 lb/hr
- (5) Number of tube columns (N) = 16.8 (without 25% extra tubes)
- (6) Reynolds number displayed by flue gas (Re) = 36,700
- (7) Flue gas velocity (v) = 94 ft/sec
- (8) Total tube length per column (LM) = 1450 ft
- (9) Total heat transfer area = 8,000 ft²
- (10) Outside (of tube) heat transfer coefficient (h_o) = 32 Btu/hr-ft²-°F
- (11) Assuming a square duct for four individual reheat modules, the exchanger dimensions can be calculated:

Duct width $\approx$ 9.5 ft

$$\begin{array}{ccccccccccc} \text{Total exchanger} & & & & & & & & & & & & \\ \text{surface area} & = & 4 & \times & L & \times & M & \times & N & \times & 3.14 & \times & (\frac{1}{12}) & \times & 1.25 \\ & & \downarrow & & \downarrow & & \downarrow & & \downarrow & & \downarrow & & \downarrow & & \downarrow \\ & & \text{modules} & & 9.5 & & 38 & & 16.8 & & \pi & & D & & 25\% \\ & & & & \text{ft} & & & & & & & & \text{ft} & & \text{safety} \\ & \approx & 8000 & \text{ft}^2 & & & & & & & & & & & \text{factor} \end{array}$$

FAN CALCULATIONS

Without an inline reheater, the total system pressure drop would be 34 inches of water. Adding the tube bundles increases the pressure drop and subsequently the fan horsepower and capital cost. These additional costs are charged to the reheat system. With the indirect and exit gas

recirculation cases, an auxiliary fan is required for each module rather than an increase in the main fan size.

In developing costs, an estimated mid-1978 price index was used. Shaft horsepower was calculated as follows (Ref. 36):

$$HP = .000157 \times q \Delta P / \eta \quad (D-24)$$

where:

q = the gas flow rate, acfm

ΔP = the developed head, in. H_2O

η = fan efficiency

HP = shaft horsepower

Example

For a system having a flue gas flow rate of 5.14×10^6 lbs/hr and no reheater (Case A, Figure D-1), four 2760 horsepower fans were required. The addition of an inline reheater results in an additional six-inch pressure drop to this system (see Case B, Figure D-1). This ultimately requires the use of four 3260 horsepower fans. The incremental capital cost and power costs are shown in Table E-1 and Appendix D.

STACK SIZE

A significant increase in flow rate occurs in the stack with the indirect hot air method. Rather than increase the stack velocity and therefore the pressure drop, it was decided to increase the stack diameter and keep the velocity constant. In actuality, both velocity and diameter would probably be increased. A constant 60 ft/sec velocity was selected. This gave a 22.4 ft diameter stack for the base case 500-MW plant.

Again, only the incremental stack cost was charged to the reheat system. It was assumed the stack height would be constant and that the price was linear with diameter. A base price of \$2,550,000 (1978\$) for the stack (22.4 ft diameter) was used. The incremental stack cost is calculated as follows:

$$\Delta \text{Stack Cost} = \left(\frac{D_{\text{new}}}{22.4} - 1 \right) \$2,550,000 \quad (\text{D-25})$$

$$\text{where } D_{\text{new}} = \left[\frac{(\dot{m}_{\text{fg}} + \dot{m}_{\text{air}}) (\text{lb/hr})}{\rho (\text{lb/ft}^3) \times 60 (\text{ft/sec}) \times 3600 (\text{sec/hr}) \pi} \right]^{.5} \quad (\text{D-26})$$

NOMENCLATURE

A	area, (ft^2)
C	heat capacity, (Btu/lb-F°)
D	tube or stack diameter, (ft)
f	friction factor, (dimensionless)
g_c	dimensional constant, ($\text{ft-lb}_F/\text{lb}_m\text{-sec}^2$)
h	gas film coefficient, ($\text{Btu/hr-ft}^2\text{-F}^\circ$)
HP	power, (hp)
j	j-factor function, (dimensionless)
K	thermal conductivity, ($\text{Btu/F}^\circ\text{-ft-sec}$)
L	tube length, (ft)
M	number of tube rows per column
$\dot{m}$	mass flow rate, (lb/hr)
MW	molecular weight, (lb/lb mole)
n	exponent in j-factor correlation
N	number of tube columns
$\bar{p}$	average pressure, (psia)
P	pressure, (ft of fluid)
Pr	Prandtl number, (dimensionless)
q	volumetric flow rate, (ft^3/min)
Q	heat transferred, (Btu/hr)
R	gas constant, ($10.73 \text{ psia ft}^3/\text{R}^\circ\text{-lb mole}$)
Re	Reynolds number, (dimensionless)
S	tube spacing, (ft)
t	temperature, ($^\circ\text{F}$)
U	overall heat transfer coefficient, ($\text{Btu/hr-ft}^2\text{-}^\circ\text{F}$)
v	maximum velocity, (ft/sec)
W	total mass flow rate, (lb/sec)

Greek

λ	latent heat of vaporization, (Btu/lb)
α	coefficient in j-factor correlation
μ	viscosity, ($\text{lb}_M/\text{ft-sec}$)
η	efficiency
ρ	density, (lb_M/ft^3)
θ	heating fluid temperature, ($^{\circ}\text{F}$)
Δ	difference in two quantities (such as temperature, pressure, etc.)

Subscripts

EB	energy balance
FG	flue gas
H	heat transfer
L	logarithmic
S	steam
A	air
M	momentum transfer
1	momentum transfer correlation
2	heat transfer correlation

APPENDIX E

REHEAT CONFIGURATION COMPONENT COST ASSUMPTIONS

APPENDIX E

REHEAT CONFIGURATION COMPONENT COST ASSUMPTIONS

INTRODUCTION

This Appendix presents the bases for the costs used for each component of the reheat system. These include equipment costs, installation costs, indirect costs, operating costs and other items included in the annual revenue requirement. The equipment considered, as well as the bases used, is presented below. Cost summary sheets for each reheat system evaluated are presented at the end of this Appendix.

DIRECT EQUIPMENT COSTS

Heat Exchanger

Materials--

Responses to the industry questionnaire (distributed to reheat users, A/E firms, and FGD process vendors) indicate that:

- (1) Carbon steel tubes are used or recommended for use in most indirect hot air reheat systems, and
- (2) Current practices and recommendations for inline reheat range from carbon steel to Inconel 625.

Although there is no industrial experience with exit gas recirculation reheat, the gases in contact with the exchanger would probably be less corrosive than that in contact with an inline exchanger.

The tube materials used for inline reheat will be very site specific and depend on the:

- (1) Chloride and sulfur content of the coal
- (2) Type of scrubbing system used
- (3) Open or closed loop water system
- (4) Quality of the steam level or hot water used for reheat

In this study, costs of inline reheat exchangers were evaluated using carbon steel, stainless steel Type 316, and Inconel 625 alloys. Tube life was estimated to be 2, 4, and 8 years, respectively for these various alloys.

Tube Dimensions--

Based on survey information, a tube wall thickness of 0.1-inch was selected for inline reheaters and 0.05-inch for indirect hot air reheaters. The exit gas recirculation reheaters were designed conservatively, with 0.1-inch thick tube walls. The thin tube for indirect hot air reheaters was selected because of less severe service compared to the inline reheaters. For all cases 1-inch OD tubes were specified.

Tube Life--

Based on survey results, the following tube life expectancy was assumed (for carbon steel): inline - 2 years, indirect - 10 years. The tube life for exit gas recirculation reheaters made of carbon steel was estimated at 4 years. An average tube life of up to 4 years may be expected using stainless steel in inline service. Because industry's use of Inconel has been very limited, no tube life data were available from these sources; however, vendors that were contacted indicated that the average life of Inconel tubes could be expected to be approximately four times longer than the life of carbon steel tubes. Consequently, Inconel tubes were estimated to have a life of eight years in these analyses. It should be pointed out that the use of these tube life figures are estimates and that definitive operating experience to confirm these numbers is not available.

Tube Costs--

Based on contacts with exchanger vendors, the following costs for delivered prices of tube bundles specified above were developed:

Tube Thickness for 1-in. OD tubes (inches)	<u>0.1</u>	<u>0.05</u>
Cost (\$/ft ² of surface area):		
Carbon Steel	20	11
Stainless Steel (316L)	39	21
Inconel 625	70	39

The exchanger vendors indicated that the reheat exchangers being looked at in this study would essentially have a scale factor of 1.0 because of their large size.

Fins--

All the reheaters in this study were assumed to consist of bare tubes with no fins. Data obtained by the survey indicate that bare, unfinned tubes are commonly used for inline reheat. An indirect hot air reheater would probably be designed with finned tubes to reduce the physical size of the exchanger. Exchanger vendors indicated that replacing the bare tubes with finned tubes would probably not change the cost of the system appreciably. Only the physical size of the exchanger would be reduced.

Main and Auxiliary Fans

Fan costs were obtained using an in-house computer program. A mid-1978 Marshall and Stevens escalation factor of 540 was used. The FGD system for the base case 500-MW plant has four scrubbing modules, each having a fan. In the exit gas recirculation and indirect systems, four auxiliary fans were added.

Incremental Stack Cost

As discussed in the previous appendix, the indirect hot air injection system required a larger stack diameter to keep the gas velocity at 60 ft/sec. Therefore, the more air injected, the greater the stack diameter and, subsequently, the cost. A base price of \$2,550,000* was used for a 300-foot high, 22.4-foot diameter stack. The cost for larger stacks was assumed to be directly proportional to the diameter.

Soot Blowers

Soot blower costs were obtained from vendors and are about \$1700 for each blower. Based on survey results, four were specified for each scrubber module for inline service. Since the exit gas recirculation method has not yet been demonstrated, the use of two soot blowers per module was assumed. None was specified for the indirect systems.

DIRECT LABOR AND MATERIALS COSTS (INSTALLATION COSTS)

The direct labor and materials (DL+M) costs for reheat exchangers (installation costs) were estimated based on information reported by McGlamery et al.²⁹ The information in this reference was used to develop an expression for installation costs:

$$DL+M = \$89,000 + SA \times \$13.4/\text{ft}^2$$

where DL+M is reheat exchanger installation costs (1978\$) and SA is exchanger surface area, ft².

The resulting installation costs are typical of costs that would be estimated using factors reported by Guthrie³⁵, Peters and Timmerhaus³⁶, Perry³⁴ and Ponder et al.³⁷.

*Installed cost

INDIRECT COSTS

Indirect costs were estimated as 45 percent of the direct investment (equipment cost, labor and materials). This factor was obtained in part from the sources mentioned above. It includes engineering, construction expenses, contractor fees, and a 20 percent contingency. It does not include interest during construction or start-up costs.

OPERATING COSTS

Steam and Hot Water Costs

The steam costs used have been derived previously in Appendix C. As developed, they vary depending on their energy level (or steam quality).

Electricity Costs

Electricity costs are based on estimated capital and operating expenses for a new 500-MW power plant. The bases for estimating these respective costs are presented below:

Capital Investment Basis

Assumed capital investment* - \$800/kW for a 500-MW plant
(mid-1978 dollars)

Operating Expense Bases

Assumed fuel costs - \$1.00/10⁶ Btu
Plant heat rate - 9000 Btu/kwh (38 percent thermal efficiency)
Fuel consumption - 428,600 lbs/hr
Coal heating value - 10,500 Btu/lb
Annual operating period - 7000 hr/yr (79.9 percent capacity factor)
Assumed operating and maintenance cost** - 7 mills/kwh

* Includes installed cost, engineering, contingency, interest during construction, start-up costs.

**Includes operating and maintenance cost for plant and all auxiliaries (FGD system, solid waste disposal).

Using the above operating expense bases, the operating cost was calculated from Equation E-1.

$$N = \text{annual operating cost} = \text{fuel cost} + \text{O\&M cost} + \text{depreciation} \quad (\text{E-1})$$

$$9000 \frac{\text{Btu}}{\text{kWh}} \times 7000 \frac{\text{hr}}{\text{yr}} \times 500,000 \text{ kW} \times \$1.00/10^6 \text{ Btu} + \$0.007/\text{kWh} \times$$

$$7000 \frac{\text{hr}}{\text{yr}} \times 500,000 \text{ kW} + \$800/\text{kW} \times 500,000 \text{ kW} \times \frac{1}{25} \text{ years} = \$72,000,000/\text{yr}$$

The annual revenue requirement was calculated in accordance with the expression developed in Appendix C and was determined to be \$110,000,000/year. The annual power generated is:

$$500,000 \text{ kW} \times 7000 \text{ hr/yr} = 3.5 \times 10^3 \text{ kWh/year} \quad (\text{E-2})$$

The annual revenue requirement divided by the annual power generated yields an average unit price of \$0.0314/kWh for electricity (1978\$).

Maintenance and Replacement Cost for Reheat Exchangers

The maintenance cost for the reheat exchanger is expected to be very dependent on tube life. This will be primarily associated with the replacement (equipment plus installation) of corroded tubes. The following expression was assumed for estimating total reheat system maintenance costs (annual):

$$M + R = \frac{[.25(DL+M) + \text{Exchanger Cost}]}{\text{tube life}} \quad (\text{E-3})$$

Maintenance for Other Equipment Items

The annual maintenance cost for other equipment items such as fans and direct combustion reheat systems was taken as 8 percent of the installed equipment cost.

Depreciation

Depreciation was calculated using the straight line method over 25 years.

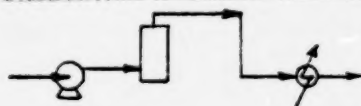
COST SUMMARY SHEETS

The capital and operating cost bases described above were used to develop the cost of the various reheat configurations as well as sensitivity studies considered. The cost of each study conducted is presented in Tables E-1 through E-38.

Note the information concerning the primary fan. The fan size listed is the size of each of 4 fans required for the case shown. For example, in Table E-1, four 3240 HP fans are required. The capital investments shown to the right reflect the incremental investment required for the fan in the reheat configuration compared to a forced draft fan configuration with no reheat. The forced draft fan base case required four 2755 HP fans to overcome a 34-in. H₂O pressure drop.

TABLE E-1. COST SUMMARY SHEET FOR INLINE REHEAT
(600 psia, dry saturated steam)

CONFIGURATION:



Required Heat Input (10^6 Btu/hr) - 66.8
Scrubbed Flue Gas:
Temperature ($^{\circ}$ F) - 131
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam:
Temperature ($^{\circ}$ F) - 486
Pressure (psia) - 600
Flow Rate (lbs/hr) - 91,300

Stack Exit Temperature ($^{\circ}$ F) - 181
Recirculation Exit Gas:
Temperature ($^{\circ}$ F) -
Flow Rate (lbs/hr) -
Reheat Air:
Ambient Temperature ($^{\circ}$ F) -
Heated Temperature ($^{\circ}$ F) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	8,100 (ft^2) ^a	\$ 20 / ft^2	162,000
Exit Temp ($^{\circ}$ F) - 181				
Exchanger DP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr- ft^2 - $^{\circ}$ F) ^b -			31.5	
Superheat Heat Transfer Coefficient (Btu/hr- ft^2 - $^{\circ}$ F) ^c -				
Primary Fan ^d :				
Size (HP) - 3240	4		\$ 38,000 each	151,000
DP (in. H ₂ O) - 40				
Auxiliary Fan ^e :				
DP (in. H ₂ O) - -	-	- (HP)	\$ - each	-
Incremental Stack Cost ^f :				
Soot Blowers:	16		\$ 1,700 each	27,000
Total Equipment Cost ^g				340,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				198,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				242,000
TOTAL CAPITAL INVESTMENT				780,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	91,300 (lbs/hr)	1.69 (\$/10 ³ lbs)	1,080,000
Electricity	1,460 (kw)	0.0314 (\$/kwh)	321,000
Primary Fan	(kw)	(\$/kwh)	-
Auxiliary Fan	(kw)	(\$/kwh)	-
Maintenance and Replacement Cost			118,000
Depreciation			31,000
TOTAL ANNUAL OPERATING COST			1,550,000
ANNUAL REVENUE REQUIRED			1,624,000

^aArea shown is 25% greater than area calculated

^bOverall heat transfer coefficient for condensing portion of exchanger

^cOverall heat transfer coefficient for desuperheat portion of exchanger

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

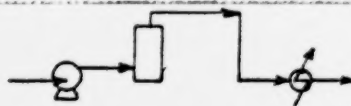
^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

Reproduced from
best available copy.

TABLE E-2. COST SUMMARY SHEET FOR INLINE REHEAT
(310 psia, dry saturated steam)

CONFIGURATION:



Required Heat Input (10⁶Btu/hr) - 66.8

Scrubbed Flue Gas:

Temperature (°F) - 131

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam:

Temperature (°F) - 420

Pressure (psia) - 310

Flow Rate (lbs/hr) - 82,900

Stack Exit Temperature (°F) - 181

Recirculation Exit Gas:

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) -

Heated Temperature (°F) -

Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	10,800 (ft ²) ^a	\$ 20 ft ²	216,000
Exit Temp (°F) - 181				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu hr-ft ² -°F) ^b - 29.6				
Superheat Heat Transfer Coefficient (Btu hr-ft ² -°F) ^c -				
Primary Fan				
Size (HP) - 3240	4		\$ 38,000 each	151,000
ΔP (in. H ₂ O) - 40				
Auxiliary Fan ^d				
Size (HP) -	-	- (HP)	\$ - each	-
Incremental Stack Cost ^e				-
Stack Blowers	16		\$ 1,700 each	27,000
Total Equipment Cost ^f				394,000
Direct Labor and Materials Cost (for exchanger and stack blower installation)				234,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				283,000
TOTAL CAPITAL INVESTMENT				911,000

OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam/Hot Water	82,900 (lbs/hr)	1.73 (\$ 10 ⁶ lbs)	1,003,000
Electricity			
Primary Fan	1,460 (kw)	0.0314 (\$/kwh)	321,000
Auxiliary Fan	- (kw)	- (\$/kwh)	-
Maintenance and Replacement Cost			149,000
Depreciation			36,000
TOTAL ANNUAL OPERATING COST			1,509,000
ANNUAL REVENUE REQUIRED			1,596,000

^a Area shown is 25% greater than area calculated.

^b Overall heat transfer coefficient for condensing portion of exchanger.

^c Overall heat transfer coefficient for desuperheat portion of exchanger.

^d Primary fan's base size corresponds to a forced draft FGD process without reheat.

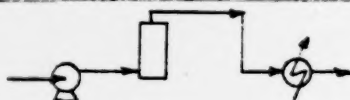
^e Auxiliary fan required for indirect hot air and exit gas recirculation configurations.

^f Incremental stack cost experienced only with indirect hot air configuration.

^g Total cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-3. COST SUMMARY SHEET FOR INLINE REHEAT
(165 psia, dry saturated steam)

CONFIGURATION



Required Heat Input (10⁶Btu/hr) - 66.8

Scrubbed Flue Gas:

Temperature (°F) - 131

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam:

Temperature (°F) - 366

Pressure (psia) - 165

Flow Rate (lbs/hr) - 78,000

Stack Exit Temperature (°F) - 181

Recirculation Exit Gas:

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) -

Heated Temperature (°F) -

Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	14,500 (ft ²) ^a	\$ 20 /ft ²	290,000
Exit Temp (°F) - 181				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			27.7	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan:				
Size (HP) - 3240	4		\$ 38,000 each	151,000
ΔP (in. H ₂ O) - 40				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) -	-	- (HP)	\$ - each	-
Incremental Stack Cost ^e :				-
Soot Blowers:	16		\$ 1,700 each	27,000
Total Equipment Cost ^f				468,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				284,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				338,000
TOTAL CAPITAL INVESTMENT				1,090,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	78,000 (lbs/hr)	1.57 (\$/10 ³ lbs)	857,000
Electricity			
Primary Fan	1460 (kw)	0.0314 (\$/kwh)	321,000
Auxiliary Fan	(kw)	(\$/kwh)	-
Maintenance and Replacement Cost			193,000
Depreciation			44,000
TOTAL ANNUAL OPERATING COST			1,415,000
ANNUAL REVENUE REQUIRED			1,519,000

^aArea shown is 25% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

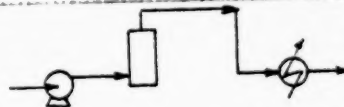
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-4. COST SUMMARY SHEET FOR INLINE REHEAT
(83 psia, dry saturated steam)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 66.8
Scrubbed Flue Gas:
Temperature ($^{\circ}$ F) - 131
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam:
Temperature ($^{\circ}$ F) - 315
Pressure (psia) - 83
Flow Rate (lbs/hr) - 74,300

Stack Exit Temperature ($^{\circ}$ F) - 181
Recirculation Exit Gas:
Temperature ($^{\circ}$ F) -
Flow Rate (lbs/hr) -
Reheat Air:
Ambient Temperature ($^{\circ}$ F) -
Heated Temperature ($^{\circ}$ F) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	20,900 (ft ²) ^a	\$ 20 (ft ²)	418,000
Exit Temp ($^{\circ}$ F) - 181				
Exchanger MP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² - $^{\circ}$ F) ^b -			25.6	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² - $^{\circ}$ F) ^c -				
Primary Fan				
Size (HP) - 3240	4		\$38,000 each	151,000
MP (in. H ₂ O) - 40				
Auxiliary Fan ^d				
Size (in. H ₂ O) -	-	- (HP)	\$ - each	-
Incremental Stack Cost ^e				
Stack Cost ^f	16		\$1,700 each	27,000
Soot Blowers				
Total Equipment Cost ^g				596,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				370,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				435,000
TOTAL CAPITAL INVESTMENT				1,401,000

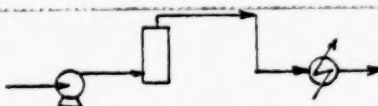
OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam Hot Water	74,400 (lbs/hr)	1.37 (\$ 10/lbs)	713,000
Electricity			
Primary Fan	1,460 (kw)	0.0314 (\$/kwh)	321,000
Auxiliary Fan	- (kw)	- (\$/kwh)	-
Maintenance and Replacement Cost			267,000
Depreciation			56,000
TOTAL ANNUAL OPERATING COST			1,357,000
ANNUAL REVENUE REQUIRED			1,490,000

^aArea shown is 15% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-5. COST SUMMARY SHEET FOR INLINE REHEAT
(39 psia, dry saturated steam)

CONFIGURATION



Required Heat Input (10⁶Btu/hr) - 66.8

Scrubbed Flue Gas:

Temperature (°F) - 131

Flow Rate (lbs/hr) - 5,140,00

Reheat Steam:

Temperature (°F) - 266

Pressure (psia) - 39

Flow Rate (lbs/hr) - 71,500

Stack Exit Temperature (°F) - 181

Recirculation Exit Gas:

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) -

Heated Temperature (°F) -

Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger:	4	33,800 (ft ²) ^a	\$ 20 ft ²	676,000
Exit Temp (°F) - 181				
Exchanger DP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -		23.0		
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -		-		
Primary Fan ^d				
Size (HP) - 3240	4		\$ 38,000 each	151,000
DP (in. H ₂ O) - 40				
Auxiliary Fan ^e				
Size (HP) - -	-	(HP)	\$ - each	-
Incremental Stack Cost ^f				
Stack Cost ^f	16		\$ 1,700 each	27,000
Soot Blowers				
Total Equipment Cost ^g				854,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				453,000
Indirect Costs (+5% of Total Equipment and Direct Labor & Material Costs)				588,000
TOTAL CAPITAL INVESTMENT				1,895,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	71,500 (lbs/hr)	1.10 (\$ 10 ⁶ /lbs)	551,000
Electricity			
Primary Fan	1,460 (kw)	0.0314 (\$/kw-hr)	321,000
Auxiliary Fan	- (kw)	- (\$/kw-hr)	-
Maintenance and Replacement Cost			407,000
Depreciation			76,000
TOTAL ANNUAL OPERATING COST			1,355,000
ANNUAL REVENUE REQUIRED			1,535,000

^aArea shown is 25% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

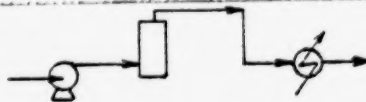
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-6. COST SUMMARY SHEET FOR INLINE REHEAT
(16 psia, dry saturated steam)

CONFIGURATION



Required Heat Input (10⁶Btu/hr) - 66.8
Scrubbed Flue Gas
Temperature (°F) - 131
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam
Temperature (°F) - 216
Pressure (psia) - 16
Flow Rate (lbs/hr) - 69,100

Stack Exit Temperature (°F) - 181
Recirculation Exit Gas
Temperature (°F) -
Flow Rate (lbs/hr) -
Reheat Air
Ambient Temperature (°F) -
Heated Temperature (°F) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	73,300 (ft ²) ^a	\$ 20 ft ²	1,466,000
Exit Temp (°F) -				
Exchanger DP (in. H ₂ O) -				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -		19.5		
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -		-		
Primary Fan ^d				
Size (HP) - 3240	4		\$38,000 each	151,000
DP (in. H ₂ O) - 40				
Auxiliary Fan ^e				
Size (in. H ₂ O) -	-	- (HP)	\$ each	
Incremental Stack Cost ^f				
Soot Blowers	16		\$1,700 each	27,000
Total Equipment Cost ^g				1,644,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				1,072,000
Indirect Costs (-5% of Total Equipment and Direct Labor & Material Costs)				1,222,000
TOTAL CAPITAL INVESTMENT				3,938,000

OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam/Hot Water	69,000 (lbs/hr)	0.78 (\$ 10 ⁶ lbs)	377,000
Electricity			
Primary Fan	1,460 (kw)	0.0314 (\$/kwh)	321,000
Auxiliary Fan	(kw)	(\$/kwh)	-
Maintenance and Replacement Cost			898,000
Depreciation			159,000
TOTAL ANNUAL OPERATING COST			1,754,000
ANNUAL REVENUE REQUIRED			2,128,000

^aArea shown is 15% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FID process without reheat.

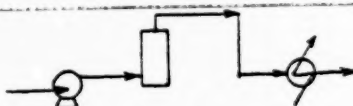
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-7. COST SUMMARY SHEET FOR INLINE REHEAT
(165 psia, hot water)

CONFIGURATION



Required Heat Input (10⁶ Btu/hr) - 66.8
Scrubbed Flue Gas:
Temperature (°F) - 131
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam:
Temperature (°F) - 366
Pressure (psia) - 165
Flow Rate (lbs/hr) - 534,000

Stack Exit Temperature (°F) - 181
Recirculation Exit Gas:
Temperature (°F) -
Flow Rate (lbs/hr) -
Reheat Air:
Ambient Temperature (°F) -
Heated Temperature (°F) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger	4	23,000 (ft ²) ^a	\$ 20 ft ²	460,000
Exit Temp. (°F) - 181				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b - 24.8				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan:				
Size (HP) - 3240	4		\$ 38,000 each	151,000
ΔP (in. H ₂ O) - 40				
Auxiliary Fan ^d :				
Size (HP) - -	-	- (HP)	\$ - each	-
Incremental Stack Cost ^e	16		\$ 1,700 each	27,000
Soot Blowers:				
Total Equipment Cost ^f				638,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				398,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				466,000
TOTAL CAPITAL INVESTMENT				1,502,000

OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	534,000 (lbs/hr)	0.24 (\$ 10/lbs)	897,000
Electricity:			
Primary Fan	1,460 (kw)	0.0314 (\$/kw)	321,000
Auxiliary Fan	- (kw)	- (\$/kw)	-
Maintenance and Replacement Cost			292,000
Depreciation			60,000
TOTAL ANNUAL OPERATING COST			1,570,000
ANNUAL REVENUE REQUIRED			1,713,000

^a Area shown is 25% greater than area calculated.

^b Overall heat transfer coefficient for condensing portion of exchanger.

^c Overall heat transfer coefficient for desuperheat portion of exchanger.

^d Primary fan's base size corresponds to a forced draft FGD process without reheat.

^e Auxiliary fan required for indirect hot air and exit gas recirculation configurations.

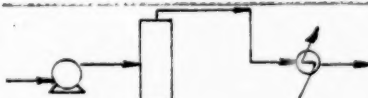
^f Incremental stack cost experienced only with indirect hot air configuration.

^g Total cost of equipment that is needed as a result of reheat. The fan and incremental

stack costs included in this total are installed costs.

TABLE E-8. COST SUMMARY SHEETS FOR INLINE REHEAT SENSITIVITY STUDY (Case A, 316L Stainless Steel Tubes)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 66.8
 Scrubbed Flue Gas
 Temperature ($^{\circ}$ F) - 131
 Flow Rate (lbs/hr) - 5,140,000
 Reheat Steam:
 Temperature ($^{\circ}$ F) - 366
 Pressure (psia) - 165
 Flow Rate (lbs/hr) - 78,000

Stack Exit Temperature ($^{\circ}$ F) - 181
 Recirculation Exit Gas
 Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -
 Reheat Air
 Ambient Temperature ($^{\circ}$ F) -
 Heated Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	14,500 (ft ²) ^a	\$ 39 / ft ²	566,000
Exit Temp ($^{\circ}$ F) - 181				
Exchanger SP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b - 27.7				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan	4		\$ 38,000 each	151,000
Size (HP) - 3240				
SP (in. H ₂ O) - 40				
Auxiliary Fan ^d	-	- (HP)	\$ - each	-
SP (in. H ₂ O) - -				
Incremental Stack Cost ^e				
Soot Blowers	16		\$ 1,700 each	27,000
Total Equipment Cost ^f				744,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				284,000
Indirect Costs (-5% of Total Equipment and Direct Labor & Material Costs)				463,000
TOTAL CAPITAL INVESTMENT				1,491,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam Hot Water	78,000 (lbs/hr)	1.57 (\$ 10 ⁶ lbs)	857,000
Electricity			
Primary Fan	1,460 (kw)	0.0314 (\$ /kwh)	321,000
Auxiliary Fan	- (kw)	- (\$ /kwh)	-
Maintenance and Replacement Cost			171,000
Depreciation			60,000
TOTAL ANNUAL OPERATING COST			1,409,000
ANNUAL REVENUE REQUIRED			1,551,000

^a Area shown is 25% greater than area calculated.

^b Overall heat transfer coefficient for condensing portion of exchanger.

^c Overall heat transfer coefficient for desuperheat portion of exchanger.

^d Primary fan's base size corresponds to a forced draft FGD process without reheat.

^e Auxiliary fan required for indirect hot air and exit gas recirculation configurations.

^f Incremental stack cost experienced only with indirect hot air configuration.

^g Total cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-9. COST SUMMARY SHEET FOR TURBINE REHEAT SENSITIVITY STUDY (Case B, Inconel 625 Exchanger Tubes)

CONFIGURATION



Required Heat Input (10⁶ Btu/hr) - 66.8
 Scrubbed Flue Gas:
 Temperature (°F) - 131
 Flow Rate (lbs/hr) - 5,140,000
 Reheat Steam:
 Temperature (°F) - 366
 Pressure (psia) - 165
 Flow Rate (lbs/hr) - 78,000

Stack Exit Temperature (°F) - 181
 Recirculation Exit Gas:
 Temperature (°F) -
 Flow Rate (lbs/hr) -
 Reheat Air:
 Ambient Temperature (°F) -
 Heated Temperature (°F) -
 Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger	4	14,500 sq ft	\$ 70	1,015,000
Exit Temp (°F) - 181				
Exchanger DP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^a - 27.7				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -				
Primary Fan	4		\$ 38,000 each	151,000
Size (HP) - 3240				
DP (in. H ₂ O) - 40				
Auxiliary Fan ^c	-	- (HP)	\$ - each	-
P (in. H ₂ O) -				
Incremental Stack Cost ^d	16		\$ 1,700 each	27,000
Soot Blowers				
Total Equipment Cost ^e				1,193,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				284,000
Indirect Costs (4% of Total Equipment and Direct Labor & Material Costs)				665,000
TOTAL CAPITAL INVESTMENT				2,142,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam Hot Water	78,000 (lb/hr)	1.57 (\$/lb)	857,000
Electricity	1460 (kw)	0.0314 (\$/kwh)	321,000
Primary Fan			
Auxiliary Fan			
Maintenance and Replacement Cost			148,000
Depreciation			86,000
TOTAL ANNUAL OPERATING COST			1,412,000
ANNUAL REVENUE REQUIRED			1,615,000

^aArea shown is 35% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-10. COST SUMMARY SHEET FOR INLINE REHEAT
SENSITIVITY STUDY (Case C)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 66.8

Scrubbed Flue Gas:

Temperature ($^{\circ}$ F) - 131

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam:

Temperature ($^{\circ}$ F) - 366

Pressure (psia) - 165

Flow Rate (lbs/hr) - 78,000

Stack Exit Temperature ($^{\circ}$ F) - 181

Recirculation Exit Gas:

Temperature ($^{\circ}$ F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature ($^{\circ}$ F) -

Heated Temperature ($^{\circ}$ F) -

Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger	4	17,600 (ft ²) ^a	\$ 20 / ft ²	352,000
Exit Temp ($^{\circ}$ F) - 181				
Exchanger IP (in. H ₂ O) - 3			23.1	
Condensing Heat Transfer Coefficient (Btu hr-ft ² -°F) ^b				
Superheat Heat Transfer Coefficient (Btu hr-ft ² -°F) ^c				
Primary Fan ^d	4		\$ 19,500 each	78,000
Size (HP) - 3020				
P (in. H ₂ O) - 37				
Auxiliary Fan ^e	-	- (HP)	\$ - each	-
P (in. H ₂ O) - -				
Incremental Stack Cost ^f	16		\$ 1,700 each	27,000
Soot Blowers				457,000
Total Equipment Cost ^g				325,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				352,000
Indirect Costs (-5% of Total Equipment and Direct Labor & Material Costs)				1,134,000
TOTAL CAPITAL INVESTMENT				

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam Hot Water	78,000 (lbs/hr)	1.57 (\$ 10/lbs)	857,000
Electricity	734 (kw)	0.0314 (\$/kw)	161,000
Primary Fan	- (kw)	- (\$/kw)	-
Auxiliary Fan	- (kw)	- (\$/kw)	-
Maintenance and Replacement Cost			229,000
Depreciation			45,000
TOTAL ANNUAL OPERATING COST			1,292,000
ANNUAL REVENUE REQUIRED			1,400,000

^a Area known is 15% greater than area calculated.

^b Overall heat transfer coefficient for condensing portion of exchanger.

^c Overall heat transfer coefficient for desuperheat portion of exchanger.

^d Primary fan's base size corresponds to a forced draft FSD process without reheat.

^e Auxiliary fan required for indirect hot air and exit gas recirculation configurations.

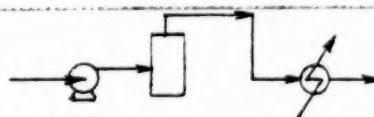
^f Incremental stack cost experienced only with indirect hot air configuration.

^g Total cost of equipment that is needed as a result of reheat. The fan and incremental

stack costs included in this total are installed costs.

TABLE E-11. COST SUMMARY SHEET FOR INLINE REHEAT SENSITIVITY STUDY (Case D)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 66.8

Scrubbed Flue Gas

Temperature ($^{\circ}$ F) - 131

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam

Temperature ($^{\circ}$ F) - 745

Pressure (psia) - 165

Flow Rate (lbs/hr) - 63,200

Stack Exit Temperature ($^{\circ}$ F) - 181

Recirculation Exit Gas

Temperature ($^{\circ}$ F) -

Flow Rate (lbs/hr) -

Reheat Air

Ambient Temperature ($^{\circ}$ F) -

Heated Temperature ($^{\circ}$ F) -

Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	13,600 ft^2 ^a	\$ 20 ft^2	272,000
Exit Temp ($^{\circ}$ F) - 181				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr- ft^2 - $^{\circ}$ F) ^b - 28.5				
Superheat Heat Transfer Coefficient (Btu/hr- ft^2 - $^{\circ}$ F) ^c - 19.0				
Primary Fan				
Size (HP) - 3240	4		\$38,000 each	151,000
ΔP (in. H ₂ O) - 40				
Auxiliary Fan ^d				
Size (HP) -		(HP)	\$ each	
Incremental Stack Cost ^e				
Stack Cost ^f	16		\$1700 each	27,000
Soot Blowers				
Total Equipment Cost ^g				450,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				272,000
Indirect Costs (-5% of Total Equipment and Direct Labor & Material Costs)				325,000
TOTAL CAPITAL INVESTMENT				1,047,000

OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	63,200 (lbs/hr)	1.93 (\$ 10/lbs)	857,000
Electricity			
Primary Fan	1,460 (kw)	0.0314 (\$/kwh)	321,000
Auxiliary Fan		(\$/kwh)	
Maintenance and Replacement Cost			182,000
Depreciation			42,000
TOTAL ANNUAL OPERATING COST			1,402,000
ANNUAL REVENUE REQUIRED			1,502,000

^aArea shown is 15% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-12. COST SUMMARY SHEET FOR INLINE REHEAT SENSITIVITY STUDY (Case E)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 66.6
 Scrubbed Flue Gas
 Temperature ($^{\circ}$ F) - 126
 Flow Rate (lbs/hr) - 5,120,000
 Reheat Steam
 Temperature ($^{\circ}$ F) - 366
 Pressure (psia) - 163
 Flow Rate (lbs/hr) - 48,100

Stack Exit Temperature ($^{\circ}$ F) - 176
 Recirculation Exit Gas
 Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -
 Reheat Air
 Ambient Temperature ($^{\circ}$ F) -
 Heated Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	9300 (ft ²) ^a	\$ 20 /ft ²	186,000
Exit Temp ($^{\circ}$ F) - 156				
Exchanger IP (in H ₂ O) - 3				
Condensing Heat Transfer Coefficient (Btu hr-ft ² - $^{\circ}$ F) ^b		24.7		
Superheat Heat Transfer Coefficient (Btu hr-ft ² - $^{\circ}$ F) ^c				
Primary Fan	4		\$ <18,000> /each	<73,000>
Size (HP) - 2580				
IP (in H ₂ O) - 37				
Auxiliary Fan ^d			\$ /each	
IP (in H ₂ O) -		(HP)		
Incremental Stack Cost ^e				
Stack Cost ^f	16		\$ 1,700 /each	27,000
Shot Blowers				
Total Equipment Cost ^g				140,000
Direct Labor and Materials Cost (for exchanger and shot blower installation)				214,000
Indirect Costs (+5% of Total Equipment and Direct Labor & Material Costs)				159,000
TOTAL CAPITAL INVESTMENT				513,000

OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	48,100 (lbs/hr)	1.57 (\$ 10 ⁶ /hr)	528,000
Electricity			
Primary Fan	<536> (kw)	0.0314 (\$/kwh)	<118,000>
Auxiliary Fan	(kw)	(\$/kwh)	
Maintenance and Replacement Cost			114,000
Depreciation			21,000
TOTAL ANNUAL OPERATING COST			545,000
ANNUAL REVENUE REQUIRED			594,000

^aArea shown is 25% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

Reproduced from
best available copy.

TABLE E-13. COST SUMMARY SHEET FOR INLINE REHEAT (Case F)

CONFIGURATION



Required Heat Input (10⁶Btu/hr) - 95

Scrubbed Flue Gas:

Temperature (°F) - 125.5

Flow Rate (lbs/hr) - 5,120,000

Reheat Steam:

Temperature (°F) - 366

Pressure (psia) - 165

Flow Rate (lbs/hr) - 78,000

Stack Exit Temperature (°F) - 196.9

Recirculation Exit Gas:

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) -

Heated Temperature (°F) -

Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger	4	14,800 (ft ²) ^a	\$ 20 (ft ²)	296,000
Exit Temp (°F) - 175.5				
Exchanger IP (in H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			26.2	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan ^d	4		\$ 2800 each	11,000
Size (HP) - 2800				
P (in H ₂ O) -				
Auxiliary Fan ^d			\$ each	
P (in H ₂ O) -				
Incremental Stack Cost ^e	16		\$ 1700 each	27,000
Soot Blowers				
Total Equipment Cost ^b				334,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				288,000
Indirect Costs (4% of Total Equipment and Direct Labor & Material Costs)				280,000
TOTAL CAPITAL INVESTMENT				902,000

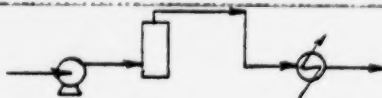
OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam Hot Water	78,000 (lbs/hr)	1.57 (\$ 10 lbs)	857,000
Electricity			
Primary Fan	131 (kw)	0.0314 (\$/kwh)	29,000
Auxiliary Fan			
Maintenance and Replacement Cost			185,000
Depreciation			36,000
TOTAL ANNUAL OPERATING COST			1,107,000
ANNUAL REVENUE REQUIRED			1,193,000

^aArea shown is 15% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FID process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-14. COST SUMMARY SHEET FOR INLINE REHEAT (Case G)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 66.8
 Scrubbed Flue Gas:
 Temperature ($^{\circ}$ F) - 131
 Flow Rate (lbs/hr) - 5,140,000
 Reheat Steam:
 Temperature ($^{\circ}$ F) - 366
 Pressure (psia) - 165
 Flow Rate (lbs/hr) - 78,000

Stack Exit Temperature ($^{\circ}$ F) - 181
 Recirculation Exit Gas:
 Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -
 Reheat Air:
 Ambient Temperature ($^{\circ}$ F) -
 Heated Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	14,500 ft^2 ^a	\$ 20 ft^2	290,000
Exit Temp. ($^{\circ}$ F) - 181				
Exchanger LP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			27.7	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan				
Size (HP) - 3240	4		\$ 38,000 each	151,000
LP (in. H ₂ O) - 40				
Auxiliary Fan ^d				
LP (in. H ₂ O) -		(HP)	\$ each	
Incremental Stack Cost ^e				
Soot Blowers	16		\$ 1,700 each	27,000
Total Equipment Cost ^f				468,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				284,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				338,000
TOTAL CAPITAL INVESTMENT				1,090,000

OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	78,000 (lbs/hr)	1.57 (\$ 10 lbs)	857,000
Electricity			
Primary Fan	1460 (kw)	0.0314 (\$/kwh)	321,000
Auxiliary Fan	(kw)	(\$/kwh)	
Maintenance and Replacement Cost			373,000
Depreciation			44,000
TOTAL ANNUAL OPERATING COST			1,595,000
ANNUAL REVENUE REQUIRED			1,699,000

^aArea shown is 15% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
 Total cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-15. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(600 psia, dry saturated steam, air approach
temperature = 80°F, $\Delta T_{\text{flue gas}} = 50^\circ\text{F}$)

CONFIGURATION:



Required Heat Input (10³Btu/hr) - 102
Scrubbed Flue Gas:
Temperature (°F) - 130
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam:
Temperature (°F) - 486
Pressure (psia) - 600
Flow Rate (lbs/hr) - 138,000

Stack Exit Temperature (°F) - 180
Recirculation Exit Gas:
Temperature (°F) -
Flow Rate (lbs/hr) -
Reheat Air:
Ambient Temperature (°F) - 60
Heated Temperature (°F) - 406
Flow Rate (lbs/hr) - 1,180,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	21,500 (ft ²) ^a	\$ 11 /ft ²	237,000
Exit Temp. (°F) - 406				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b - 26.2				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) - 9.3	4	114 (HP)	\$22,800 each	91,000
Incremental Stack Cost ^e :				
Stack Blowers:	-		\$ - each	286,000
Total Equipment Cost ^f :				614,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				378,000
Indirect Costs (4% of Total Equipment and Direct Labor & Material Costs)				406,000
TOTAL CAPITAL INVESTMENT				1,398,000

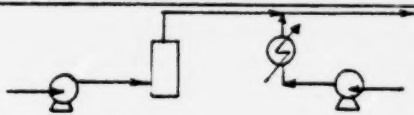
OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	138,000 (lbs/hr)	1.69 (\$/10 ³ lbs)	1,632,000
Electricity			
Primary Fan	(kw)	(\$/kwh)	
Auxiliary Fan	340 (kw)	0.0314 (\$/kwh)	75,000
Maintenance and Replacement Cost			40,000
Depreciation			56,000
TOTAL ANNUAL OPERATING COST			1,803,000
ANNUAL REVENUE REQUIRED			1.94 x 10 ⁵

^aArea shown is 10% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-16. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(310 psia, dry saturated steam; air approach
temperature = 80°F, $\Delta T_{\text{flue gas}} = 50^\circ\text{F}$)

CONFIGURATION:



Required Heat Input (10^6Btu/hr) - 117

Scrubbed Flue Gas:

Temperature ($^\circ\text{F}$) - 130

Flow Rate (lbs/hr) - 3,140,000

Reheat Steam:

Temperature ($^\circ\text{F}$) - 420

Pressure (psia) - 310

Flow Rate (lbs/hr) - 143,000

Stack Exit Temperature ($^\circ\text{F}$) - 180

Recirculation Exit Gas:

Temperature ($^\circ\text{F}$) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature ($^\circ\text{F}$) - 60

Heated Temperature ($^\circ\text{F}$) - 340

Flow Rate (lbs/hr) - 1,690,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	27,500(ft^2) ^a	\$ 11 / ft^2	302,000
Exit Temp. ($^\circ\text{F}$) - 340				
Exchanger ΔP (in. H_2O) - 6	6			
Condensing Heat Transfer Coefficient ($\text{Btu/hr-ft}^2-^\circ\text{F}$) ^b -			26.23	
Superheat Heat Transfer Coefficient ($\text{Btu/hr-ft}^2-^\circ\text{F}$) ^c -				
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H_2O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H_2O) - 9.3	4	163 (HP)	\$ 27,000 each	108,000
Incremental Stack Cost ^e :				
Soot Blowers:	-		\$ - each	393,000
Total Equipment Cost ^f				803,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				458,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				367,000
TOTAL CAPITAL INVESTMENT				1,828,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	143,000 (lbs/hr)	1.73 (\$/10 ³ lbs)	1,732,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	485 (kw)	0.0314 (\$/kwh)	107,000
Maintenance and Replacement Cost			50,000
Depreciation			73,000
TOTAL ANNUAL OPERATING COST			1,962,000
ANNUAL REVENUE REQUIRED			2.14 x 10 ⁶

^a Area shown is 10% greater than area calculated.

^b Overall heat transfer coefficient for condensing portion of exchanger.

^c Overall heat transfer coefficient for desuperheat portion of exchanger.

^d Primary fan's base size corresponds to a forced draft FGD process without reheat.

^e Auxiliary fan required for indirect hot air and exit gas recirculation configurations.

^f Incremental stack cost experienced only with indirect hot air configuration.

^g Total cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-17. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(165 psia, dry saturated steam; air approach
temperature = 40°F; ΔT flue gas = 50°F)

CONFIGURATION:



Required Heat Input (10³ Btu/hr) - 122

Scrubbed Flue Gas:

Temperature (°F) - 130

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam:

Temperature (°F) - 366

Pressure (psia) - 165

Flow Rate (lbs/hr) - 140,000

Stack Exit Temperature (°F) - 180

Recirculation Exit Gas:

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) - 60

Heated Temperature (°F) - 326

Flow Rate (lbs/hr) - 1,830,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	43,900 (ft ²) ^a	\$ 11 /ft ²	483,000
Exit Temp. (°F) - 326				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			24.25	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -			-	
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) - 9.3	4	177 (HP)	\$ 28,000 each	112,000
Incremental Stack Cost ^e :				428,000
Soot Blowers:	-		\$ - each	-
Total Equipment Cost ^f				1,023,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				678,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				765,000
TOTAL CAPITAL INVESTMENT				2,466,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	140,000 (lbs/hr)	1.57 (\$/10 ³ lbs)	1,539,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	528 (kw)	0.0314 (\$/kwh)	116,000
Maintenance and Replacement Cost			74,000
Depreciation			97,000
TOTAL ANNUAL OPERATING COST			1,826,000
ANNUAL REVENUE REQUIRED			2.06 x 10 ⁶

^aArea shown is 10% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

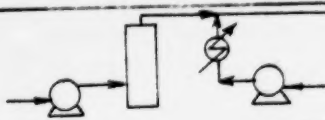
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-18. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(165 psia, dry saturated steam; air approach
temperature = 80°F; $\Delta T_{\text{flue gas}} = 50^\circ\text{F}$)

CONFIGURATION:



Required Heat Input (10^6Btu/hr) - 142

Scrubbed Flue Gas:

Temperature ($^\circ\text{F}$) - 130

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam:

Temperature ($^\circ\text{F}$) - 366

Pressure (psia) - 165

Flow Rate (lbs/hr) - 164,000

Stack Exit Temperature ($^\circ\text{F}$) - 180

Recirculation Exit Gas:

Temperature ($^\circ\text{F}$) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature ($^\circ\text{F}$) - 60

Heated Temperature ($^\circ\text{F}$) - 286

Flow Rate (lbs/hr) - 2,520,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	35,300 (ft^2) ^a	\$ 11 / ft^2	388,000
Exit Temp. ($^\circ\text{F}$) - 286				
Exchanger ΔP (in. H_2O) - 6				
Condensing Heat Transfer Coefficient ($\text{Btu/hr-ft}^2\text{-}^\circ\text{F}$) ^b - 27.3				
Superheat Heat Transfer Coefficient ($\text{Btu/hr-ft}^2\text{-}^\circ\text{F}$) ^c -				
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H_2O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H_2O) - 9.3	4	243 (HP)	\$32,900 each	132,000
Incremental Stack Cost ^e :				573,000
Soot Blowers:			\$ - each	-
Total Equipment Cost ^f				1,093,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				563,000
Indirect Costs (4% of Total Equipment and Direct Labor & Material Costs)				745,000
TOTAL CAPITAL INVESTMENT				2,401,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	164,000 (lbs/hr)	1.57 ($\$/10^3\text{lbs}$)	1,802,000
Electricity			
Primary Fan	(kw)	($\$/\text{kwh}$)	-
Auxiliary Fan	725 (kw)	0.0314 ($\$/\text{kwh}$)	159,000
Maintenance and Replacement Cost			63,000
Depreciation			96,000
TOTAL ANNUAL OPERATING COST			2,120,000
ANNUAL REVENUE REQUIRED			2.35×10^6

- ^aArea shown is 10% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-19. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(165 psia, dry saturated steam; air approach
temperature = 120°F; $\Delta T_{\text{flue gas}} = 50^\circ\text{F}$)

CONFIGURATION:



Required Heat Input (10³Btu/hr) - 188
Scrubbed Flue Gas:
Temperature (°F) - 130
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam:
Temperature (°F) - 366
Pressure (psia) - 165
Flow Rate (lbs/hr) - 216,000

Stack Exit Temperature (°F) - 180
Recirculation Exit Gas:
Temperature (°F) -
Flow Rate (lbs/hr) -
Reheat Air:
Ambient Temperature (°F) - 60
Heated Temperature (°F) - 246
Flow Rate (lbs/hr) - 4,050,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	35,500 (ft ²) ^a	\$ 11 /ft ²	391,000
Exit Temp. (°F) - 246				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			30.27	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -			-	
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) - 9.3	4	390 (HP)	\$42,600 each	170,000
Incremental Stack Cost ^e :				
Soot Blowers:	-		\$ - each	372,000
Total Equipment Cost ^f				- 1,433,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				- 565,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				- 899,000
TOTAL CAPITAL INVESTMENT				- 2,897,000

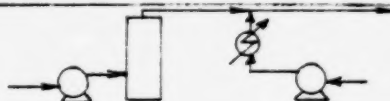
OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	216,000 (lbs/hr)	1.57 (\$/10 ³ lbs)	2,373,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	1,160 (kw)	0.0314 (\$/kwh)	255,000
Maintenance and Replacement Cost			67,000
Depreciation			116,000
TOTAL ANNUAL OPERATING COST			2,811,000
ANNUAL REVENUE REQUIRED			3.09 x 10 ⁶

^aArea shown is 10% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-20. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(600 psia, dry saturated steam; air approach
temperature = 80°F; heat input specified)

CONFIGURATION



Required Heat Input (10⁶Btu/hr) - 66.8

Scrubbed Flue Gas:

Temperature (°F) - 130

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam:

Temperature (°F) - 486

Pressure (psia) - 600

Flow Rate (lbs/hr) - 90,400

Stack Exit Temperature (°F) - 165

Recirculation Exit Gas:

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) - 60

Heated Temperature (°F) - 406

Flow Rate (lbs/hr) - 773,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	14,100 (ft ²) ^a	\$ 11 /ft ²	155,000
Exit Temp. (°F) - 406				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			26.2	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -			-	
Primary Fan ^d :				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^e :				
ΔP (in. H ₂ O) - 9.3	4	300 (HP)	\$ 19,000 each	76,000
Incremental Stack Cost ^f :				160,000
Soot Blowers:	-		\$ - each	-
Total Equipment Cost ^g				391,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				278,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				301,000
TOTAL CAPITAL INVESTMENT				970,000

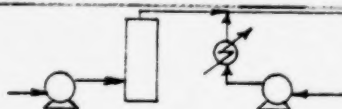
OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	90,400 (lbs/hr)	1.69 (\$/10 ³ lbs)	1,069,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	224 (kw)	0.0314 (\$/kwh)	49,000
Maintenance and Replacement Cost			29,000
Depreciation			39,000
TOTAL ANNUAL OPERATING COST			1,186,000
ANNUAL REVENUE REQUIRED			1.28 x 10 ⁶

^aArea shown is 10% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-21. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(310 psia, dry saturated steam; air approach
temperature = 80°F; heat input specified)

CONFIGURATION:



Required Heat Input (10³Btu/hr) - 66.8

Scrubbed Flue Gas:

Temperature (°F) - 130

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam:

Temperature (°F) - 420

Pressure (psia) - 310

Flow Rate (lbs/hr) - 82,000

Stack Exit Temperature (°F) - 162

Recirculation Exit Gas:

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) - 60

Heated Temperature (°F) - 340

Flow Rate (lbs/hr) - 955,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	15,700 (ft ²) ^a	\$ 11 /ft ²	173,000
Exit Temp. (°F) - 340				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			26.23	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan ^d :				
Size (HP) - 2755	4		\$ each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^e :				
ΔP (in. H ₂ O) - 9.3	4	364 (HP)	\$ 20,700 each	83,000
Incremental Stack Cost ^f :				195,000
Soot Blowers:	-		\$ - each	-
Total Equipment Cost ^g				451,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				300,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				338,000
TOTAL CAPITAL INVESTMENT				1,089,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	82,000 (lbs/hr)	1.73 (\$/10 ³ lbs)	993,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	271 (kw)	0.0314 (\$/kwh)	60,000
Maintenance and Replacement Cost			31,000
Depreciation			44,000
TOTAL ANNUAL OPERATING COST			1,128,000
ANNUAL REVENUE REQUIRED			1.23 x 10 ⁶

^aArea shown is 10% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

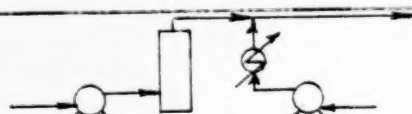
^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental

stack costs included in this total are installed costs.

TABLE E-22. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(165 psia, dry saturated steam; air approach
temperature = 40°F; heat input specified)

CONFIGURATION:



Required Heat Input (10³ Btu/hr) - 66.8

Scrubbed Flue Gas:

Temperature (°F) - 130

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam:

Temperature (°F) - 366

Pressure (psia) - 165

Flow Rate (lbs/hr) - 77,000

Stack Exit Temperature (°F) - 161

Recirculation Exit Gas:

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) - 60

Heated Temperature (°F) - 326

Flow Rate (lbs/hr) - 1,010,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	24,100 (ft ²) ^a	\$ 11 /ft ²	265,000
Exit Temp. (°F) - 326				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b - 24.33				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) - 9.3	4	388 (HP)	\$ 21,300 each	85,000
Incremental Stack Cost ^e :				204,000
Soot Blowers:	-		\$ - each	-
Total Equipment Cost ^f				554,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				412,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				435,000
TOTAL CAPITAL INVESTMENT				1,401,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	77,000 (lbs/hr)	1.57 (\$/10 ³ lbs)	845,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	289 (kw)	0.0314 (\$/kwh)	64,000
Maintenance and Replacement Cost			44,000
Depreciation			56,000
TOTAL ANNUAL OPERATING COST			1,009,000
ANNUAL REVENUE REQUIRED			1.14 x 10 ⁶

^aArea shown is 10% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

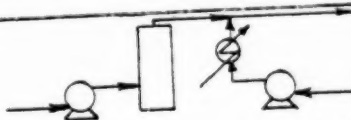
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-23. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(165 psia, dry saturated steam; air approach
temperature = 80°F; heat input specified)

CONFIGURATION:



Required Heat Input (10⁶Btu/hr) - 66.8
Scrubbed Flue Gas:
Temperature (°F) - 130
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam:
Temperature (°F) - 366
Pressure (psia) - 165
Flow Rate (lbs/hr) - 77,000

Stack Exit Temperature (°F) - 158
Recirculation Exit Gas:
Temperature (°F) -
Flow Rate (lbs/hr) -
Reheat Air:
Ambient Temperature (°F) - 60
Heated Temperature (°F) - 286
Flow Rate (lbs/hr) - 1,190,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	16,600 (ft ²) ^a	\$ 11 /ft ²	183,000
Exit Temp. (°F) - 286				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b - 27.3				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^e :				
ΔP (in. H ₂ O) - 9.3	4	460 (HP)	\$23,000 each	92,000
Incremental				238,000
Stack Cost ^f :	-		\$ - each	-
Soot Blowers:				
Total Equipment Cost ^g				513,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				312,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				371,000
TOTAL CAPITAL INVESTMENT				1,196,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	77,000 (lbs/hr)	1.57 (\$/10 ³ lbs)	845,000
Electricity			-
Primary Fan	- (kw)	- (\$/kwh)	75,000
Auxiliary Fan	343 (kw)	0.0314 (\$/kwh)	33,000
Maintenance and Replacement Cost			48,000
Depreciation			1,001,000
TOTAL ANNUAL OPERATING COST			1.11 x 10 ⁶
ANNUAL REVENUE REQUIRED			

^aArea shown is 10% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-24. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(165 psia, dry saturated steam; air approach
temperature = 120°F; heat input specified)

CONFIGURATION:



Required Heat Input (10³Btu/hr) - 66.8

Scrubbed Flue Gas:

Temperature (°F) - 130

Flow Rate (lbs/hr) - 5,140,000

Reheat Steam:

Temperature (°F) - 366

Pressure (psia) - 165

Flow Rate (lbs/hr) - 76,600

Stack Exit Temperature (°F) - 155

Recirculation Exit Gas:

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) - 60

Heated Temperature (°F) - 246

Flow Rate (lbs/hr) - 1,440,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	12,600 (ft ²) ^a	\$ 11 /ft ²	139,000
Exit Temp. (°F) - 246				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b - 30.4				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) - 9.3	4	560 (HP)	\$ 253,000 each	101,000
Incremental Stack Cost ^e :				287,000
Soot Blowers:	-		\$ - each	-
Total Equipment Cost ^f				527,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				258,000
Indirect Costs (~5% of Total Equipment and Direct Labor & Material Costs)				353,000
TOTAL CAPITAL INVESTMENT				1,138,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	76,600 (lbs/hr)	1.57 (\$/10 ³ lbs)	841,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	418 (kw)	0.0314 (\$/kwh)	92,000
Maintenance and Replacement Cost			28,000
Depreciation			46,000
TOTAL ANNUAL OPERATING COST			1,007,000
ANNUAL REVENUE REQUIRED			1.12 x 10 ⁶

^aArea shown is 10% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

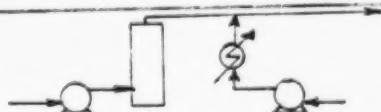
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-25. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT
(16 psia, dry saturated steam; air approach
temperature = 80°F; heat input specified)

CONFIGURATION:



Required Heat Input (10³Btu/hr) - 66.8

Scrubbed Flue Gas:

Temperature (°F) - 130
Flow Rate (lbs/hr) - 3,140,000

Reheat Steam:

Temperature (°F) - 216
Pressure (psia) - 16
Flow Rate (lbs/hr) - 67,100

Stack Exit Temperature (°F) - 133

Recirculation Exit Gas:

Temperature (°F) -
Flow Rate (lbs/hr) -

Reheat Air:

Ambient Temperature (°F) - 60
Heated Temperature (°F) - 136
Flow Rate (lbs/hr) - 3,530,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	19,900 (ft ²) ^a	\$ 11 /ft ²	219,000
Exit Temp (°F) - 136				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			33.6	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) - 9.3	4	1980 (HP)	\$40,000 each	160,000
Incremental Stack Cost ^e :				629,000
Soot Blowers:	-		\$ - each	-
Total Equipment Cost ^f				1,008,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				356,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				614,000
TOTAL CAPITAL INVESTMENT				1,978,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	67,100 (lbs/hr)	0.78 (\$/10 ³ lbs)	367,000
Electricity			-
Primary Fan	- (kw)	- (\$/kwh)	226,000
Auxiliary Fan	1,030 (kw)	0.0314 (\$/kwh)	44,000
Maintenance and Replacement Cost			79,000
Depreciation			716,000
TOTAL ANNUAL OPERATING COST			0.90 x 10 ⁶
ANNUAL REVENUE REQUIRED			

^aArea shown is 10% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

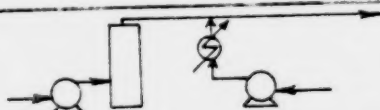
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-26. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT SENSITIVITY (CASE A)

CONFIGURATION:



Required Heat Input (10^3 Btu/hr) - 142
 Scrubbed Flue Gas:
 Temperature ($^{\circ}$ F) - 130
 Flow Rate (lbs/hr) - 5,140,000
 Reheat Steam:
 Temperature ($^{\circ}$ F) - 366
 Pressure (psia) - 165
 Flow Rate (lbs/hr) - 164,000

Stack Exit Temperature ($^{\circ}$ F) - 180
 Recirculation Exit Gas:
 Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -
 Reheat Air:
 Ambient Temperature ($^{\circ}$ F) - 60
 Heated Temperature ($^{\circ}$ F) - 286
 Flow Rate (lbs/hr) - 2,520,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger	4	29,200 (ft^2) ^a	\$ 11 / ft^2	321,000
Exit Temp ($^{\circ}$ F) - 286				
Exchanger ΔP (in. H ₂ O) - 12				
Condensing Heat Transfer Coefficient (Btu/hr- ft^2 - $^{\circ}$ F) ^b - 34.36				
Superheat Heat Transfer Coefficient (Btu/hr- ft^2 - $^{\circ}$ F) ^c -				
Primary Fan:				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) 15.3	4	400 (HP)	\$51,200 each	204,000
Incremental Stack Cost ^e :				573,000
Soot Blowers:			\$ - each	-
Total Equipment Cost ^f				1,980,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				481,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				711,000
TOTAL CAPITAL INVESTMENT				2,290,000

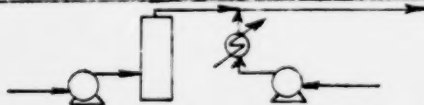
OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	162,000 (lbs/hr)	1.57 (\$/10 ³ lbs)	1,780,000
Electricity			-
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	1,190 (kw)	0.0314 (\$/kwh)	262,000
Maintenance and Replacement Cost			60,000
Depreciation			92,000
TOTAL ANNUAL OPERATING COST			2,194,000
ANNUAL REVENUE REQUIRED			2.41 x 10 ⁶

- ^aArea shown is 10% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-27. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT SENSITIVITY (CASE B)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 117
 Scrubbed Flue Gas:
 Temperature ($^{\circ}$ F) - 130
 Flow Rate (lbs/hr) - 5,140,000
 Reheat Steam:
 Temperature ($^{\circ}$ F) - 745
 Pressure (psia) - 165
 Flow Rate (lbs/hr) - 108,000

Stack Exit Temperature ($^{\circ}$ F) - 180
 Recirculation Exit Gas:
 Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -
 Reheat Air:
 Ambient Temperature ($^{\circ}$ F) - 60
 Heated Temperature ($^{\circ}$ F) - 286
 Flow Rate (lbs/hr) - 1,670,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	31,300 _{ft²} ^a	\$ 11 _{ft²}	341,000
Exit Temp ($^{\circ}$ F) - 338				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² - $^{\circ}$ F) ^b -			25.4	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² - $^{\circ}$ F) ^c -			20.9	
Primary Fan ^d :				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^e :				
ΔP (in. H ₂ O) - 9.3	4	161 (HP)	\$26,900 each	108,000
Incremental Stack Cost ^f :				385,000
Soot Blowers:	-		\$ - each	-
Total Equipment Cost ^g				834,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				505,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				603,000
TOTAL CAPITAL INVESTMENT				1,942,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	108,000 (lbs/hr)	1.93 (\$/10 ³ lbs)	1,463,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	480 (kw)	0.0314 (\$/kwh)	106,000
Maintenance and Replacement Cost			55,000
Depreciation			78,000
TOTAL ANNUAL OPERATING COST			1,702,000
ANNUAL REVENUE REQUIRED			1.89 x 10 ⁶

- ^aArea shown is 10% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-28. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT SENSITIVITY (CASE C)

CONFIGURATION



Required Heat Input (10^3 Btu/hr) - 109
 Scrubbed Flue Gas:
 Temperature ($^{\circ}$ F) - 125
 Flow Rate (lbs/hr) - 5,120,000
 Reheat Steam:
 Temperature ($^{\circ}$ F) - 366
 Pressure (psia) - 165
 Flow Rate (lbs/hr) - 97,500

Stack Exit Temperature ($^{\circ}$ F) - 175
 Recirculation Exit Gas:
 Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -
 Reheat Air:
 Ambient Temperature ($^{\circ}$ F) - 60
 Heated Temperature ($^{\circ}$ F) - 286
 Flow Rate (lbs/hr) - 1,480,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	12,400 (ft ²) ^a	\$ 11 /ft ²	147,000
Exit Temp. ($^{\circ}$ F) - 286				
Exchanger ΔP (in. H ₂ O) - 30				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² - $^{\circ}$ F) ^b -			42.51	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² - $^{\circ}$ F) ^c -			-	
Primary Fan:				
Size (HP) - 3010	4		\$ <2,800> each	<11,000>
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) - -	-	- (HP)	\$ - each	-
Incremental Stack Cost ^e	-		\$ - each	353,000
Soot Blowers:	-		\$ - each	-
Total Equipment Cost ^f				489,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				269,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				341,000
TOTAL CAPITAL INVESTMENT				1,099,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	97,500 (lbs/hr)	1.57 (\$/10 ³ lbs)	1,072,000
Electricity			
Primary Fan	760 (kw)	0.0314 (\$/kwh)	167,000
Auxiliary Fan	- (kw)	- (\$/kwh)	-
Maintenance and Replacement Cost			21,000
Depreciation			44,000
TOTAL ANNUAL OPERATING COST			1,304,000
ANNUAL REVENUE REQUIRED			1.41 x 10 ⁶

^aArea shown is 10% greater than area calculated

^bOverall heat transfer coefficient for condensing portion of exchanger

^cOverall heat transfer coefficient for desuperheat portion of exchanger

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat

^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations

^fIncremental stack cost experienced only with indirect hot air configuration

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs

CONFIGURATION



Scrubbed Flue Gas

Temperature (°F) - 125

Flow Rate (lbs/hr) - 5,120,000

Reheat Steam:

Temperature (°F) = 486

Pressure (psia) = 600

Flow Rate (lbs/hr) - 129,550

Stack Exit Temperature (°F) - 193

Recirculation Exit Gas

Temperature (°F) =

Flow Rate (lbs/hr) =

Reheat Air

Ambient Temperature (°F) = 60

Heated Temperature (°F) - 446

Flow Rate (lbs/hr) = 928,270

Item	No. Req'd.	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	17,500 (ft ²) ^a	\$ 11 ft ²	193,000
Exit Temp. (°F) - 446				
Exchanger ΔP (in. H ₂ O) - 30				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b - 35.99				
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c - -				
Primary Fan:				
Size (HP) - 2860	4		\$ <8,400> each	<34,000>
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d :				
ΔP (in. H ₂ O) - -	-	- (HP)	\$ - each	-
Incremental Stack Cost ^e	-			256,000
Soot Blowers:			\$ - each	-
Total Equipment Cost ^f				415,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				324,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				333,000
TOTAL CAPITAL INVESTMENT				1,072,000

<u>Item</u>	<u>Quantity Required</u>	<u>Cost/Unit</u>	<u>Total Annual Cost \$</u>
Steam/Hot Water	<u>129,550</u> (lbs/hr)	<u>1.69</u> (\$/10 ³ lbs)	<u>1,532,00</u>
Electricity			
Primary Fan	<u>835</u> (kw)	<u>0.0314</u> (\$/kwh)	<u>184,000</u>
Auxiliary Fan	_____ (kw)	_____ (\$/kwh)	_____
Maintenance and Replacement Cost			<u>25,000</u>
Depreciation			<u>43,000</u>
TOTAL ANNUAL OPERATING COST			<u>1,784,000</u>
ANNUAL REVENUE REQUIRED			<u>1.89 x 10⁶</u>

^aArea 400m is 10% greater than area calculated.²Overall heat transfer coefficient for condensing portion of exchanger^aOverall heat transfer coefficient for desuperheat portion of exchanger

Primary fan's base size corresponds to a forced draft FGD process without reheat.

*Auxiliary fan required for indirect hot air and exit gas recirculation configurations

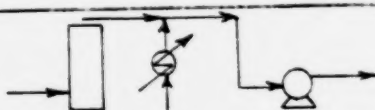
Incremental stack cost experienced only with indirect hot air configuration

*Total cost of equipment that is needed as a result of rehear. The fan and incremental.

stack costs included in this total are installed costs

TABLE E-30. COST SUMMARY SHEET FOR INDIRECT HOT AIR REHEAT SENSITIVITY (CASE E)

CONFIGURATION



Required Heat Input (10⁶Btu/hr) - 81.4

Scrubbed Flue Gas

Temperature (°F) - 126

Flow Rate (lbs/hr) - 5,120,000

Reheat Steam

Temperature (°F) - 639

Pressure (psia) - 600

Flow Rate (lbs/hr) - 66,000

Stack Exit Temperature (°F) - 176

Recirculation Exit Gas

Temperature (°F) -

Flow Rate (lbs/hr) -

Reheat Air

Ambient Temperature (°F) - 60

Heated Temperature (°F) - 446

Flow Rate (lbs/hr) - 500,000

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost/Unit	Total Cost (\$)
Reheat Exchanger:	4	12,600 (ft ²) ^a	\$ 11 / ft ²	139,000
Exit Temp. (°F) - 504				
Exchanger ΔP (in. H ₂ O) - 30				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			33.05	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -			27.82	
Primary Fan ^d :				
Size (HP) - 2580	4		\$ <23,800> each	<95,000>
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^e :				
ΔP (in. H ₂ O) -		(HP)	\$ - each	-
Incremental Stack Cost ^f :			\$ - each	116,000
Soot Blowers:				-
Total Equipment Cost ^g				160,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				258,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				188,000
TOTAL CAPITAL INVESTMENT				606,000

OPERATING COSTS

Item	Quantity Required	Cost/Unit	Total Annual Cost (\$)
Steam/Hot Water	66,000 (lbs/hr)	1.95 (\$/10 ³ lbs)	901,000
Electricity			
Primary Fan	<536> (kw)	0.0314 (\$/kwh)	<118,000>
Auxiliary Fan	- (kw)	- (\$/kwh)	-
Maintenance and Replacement Cost			13,000
Depreciation			24,000
TOTAL ANNUAL OPERATING COST			820,000
ANNUAL REVENUE REQUIRED			0.88 x 10 ⁶

^aArea shown is 10% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

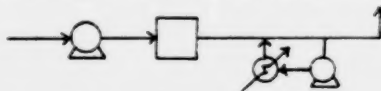
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

Reproduced from
best available copy.



TABLE E-31. COST SUMMARY SHEET FOR EXIT GAS RECIRCULATION
(600 psia, dry saturated steam; flue gas approach
temperature = 40°F)

CONFIGURATION



Required Heat Input (10⁶Btu/hr) - 66.8
Scrubbed Flue Gas
Temperature (°F) - 130
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam
Temperature (°F) - 486
Pressure (psia) - 600
Flow Rate (lbs/hr) - 90,300

Stack Exit Temperature (°F) - 180
Recirculation Exit Gas
Temperature (°F) - 446
Flow Rate (lbs/hr) - 913,000
Reheat Air
Ambient Temperature (°F) -
Heated Temperature (°F) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	37,700 (ft ²) ^a	\$ 20 (ft ²)	754,000
Exit Temp (°F) - 446				
Exchanger ΔP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b			16.9	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c			-	
Primary Fan				
Size (HP) - 2755	4		\$ - each	-
ΔP (in. H ₂ O) - 34				
Auxiliary Fan ^d				
Size (HP) - 6	4	70 (HP)	\$ 17,500 each	70,000
Incremental Stack Cost ^e				-
Stack Blowers	8		\$ 1,700 each	14,000
Total Equipment Cost ^f				838,000
Direct Labor and Materials Cost (for exchanger and stack blower installation)				595,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				645,000
TOTAL CAPITAL INVESTMENT				2,078,000

OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	90,300 (lbw/hr)	1.69 (\$ 10/lbw)	1,068,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	208 (kw)	0.0314 (\$/kwh)	46,000
Maintenance and Replacement Cost			231,000
Depreciation			83,000
TOTAL ANNUAL OPERATING COST			1,428,000
ANNUAL REVENUE REQUIRED			1.63 x 10 ⁶

- ^aArea shown is 15% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-32. COST SUMMARY SHEET FOR EXIT GAS RECIRCULATION REHEAT (600 psia, dry saturated steam; flue gas approach temperature = 80°F)

CONFIGURATION



Required Heat Input (10⁶Btu/hr) - 66.8
 Scrubbed Flue Gas
 Temperature (°F) - 130
 Flow Rate (lbs/hr) - 5,140,000
 Reheat Steam
 Temperature (°F) - 486
 Pressure (psia) - 600
 Flow Rate (lbs/hr) - 90,100

Stack Exit Temperature (°F) - 180
 Recirculation Exit Gas
 Temperature (°F) - 406
 Flow Rate (lbs/hr) - 1,080,000
 Reheat Air
 Ambient Temperature (°F) -
 Heated Temperature (°F) -
 Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	26,200 sq ft ^a	\$ 20 ft ²	524,000
Exit Temp (°F) - 406				
Exchanger IP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b			18.9	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c			-	
Primary Fan ^d				
Size (HP) - 2755	4		\$ - each	-
IP (in. H ₂ O) - 34				
Auxiliary Fan ^e				
Size (in. H ₂ O) - 6	4	83 (HP)	\$ 18,900 each	77,000
Incremental Stack Cost ^f				
Stack Blowers	8		\$ 1,700 each	14,000
Total Equipment Cost ^g				615,000
Direct Labor and Materials Cost (for exchanger and stack blower installation)				441,000
Indirect Costs (4% of Total Equipment and Direct Labor & Material Costs)				475,000
TOTAL CAPITAL INVESTMENT				1,531,000

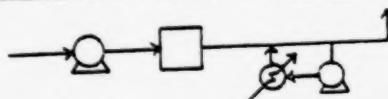
OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	90,100 (lbs/hr)	1.69 (\$ 10 ⁶ /lb)	1,066,000
Electricity			
Primary Fan	- (kW)	(\$ 10 ⁶ /kW)	-
Auxiliary Fan	248 (kW)	0.0314 (\$ 10 ⁶ /kW)	55,000
Maintenance and Replacement Cost			165,000
Depreciation			61,000
TOTAL ANNUAL OPERATING COST			1,347,000
ANNUAL REVENUE REQUIRED			1.49 x 10 ⁶

^aArea shown is 15% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for desuperheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configuration.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-33. COST SUMMARY SHEET FOR EXIT GAS RECIRCULATION
REHEAT (310 psia, dry saturated steam; flue
gas approach temperature = 120 °)

CONFIGURATION



Required Heat Input (10⁶Btu/hr) - 66.8
Scrubbed Flue Gas:
Temperature (°F) - 130
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam:
Temperature (°F) - 420
Pressure (psia) - 310
Flow Rate (lbs/hr) - 80,900

Stack Exit Temperature (°F) - 180
Recirculation Exit Gas:
Temperature (°F) - 300
Flow Rate (lbs/hr) - 2,040,000
Reheat Air:
Ambient Temperature (°F) -
Heated Temperature (°F) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	21,100 ft ²	\$ 20 ft ²	422,000
Exit Temp (°F) - 300				
Exchanger DP (in H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^a -		22.3		
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -		-		
Primary Fan				
Size (HP) - 2755	4		\$ - each	-
P (in H ₂ O) - 34				
Auxiliary Fan ^c				
P (in H ₂ O) - 6	4	157 (HP)	\$ 25,200 each	101,000
Incremental Stack Cost ^d				-
Stack Blowers	8		\$ 1,700 each	14,000
Total Equipment Cost ^e				537,000
Direct Labor and Materials Cost (for exchanger and stack blower installation)				372,000
Indirect Costs (-5% of Total Equipment and Direct Labor & Material Costs)				409,000
TOTAL CAPITAL INVESTMENT				1,318,000

OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	80,900 (lbs/hr)	1.73 (\$ 10 ⁶ /lb)	980,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	468 (kw)	0.0314 (\$/kwh)	103,000
Maintenance and Replacement Cost			137,000
Depreciation			53,000
TOTAL ANNUAL OPERATING COST			1,273,000
ANNUAL REVENUE REQUIRED			1.40 x 10 ⁶

^aArea shown is 25% greater than area calculated.

^bOverall heat transfer coefficient for condensing portion of exchanger.

^cOverall heat transfer coefficient for desuperheat portion of exchanger.

^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.

^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.

^fIncremental stack cost experienced only with indirect hot air configuration.

^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental

stack costs included in this total are installed costs.

TABLE E-34. COST SUMMARY SHEET FOR EXIT GAS RECIRCULATION
REHEAT (165 psia, dry saturated steam; flue
gas approach temperature = 80°F)

CONFIGURATION:



Required Heat Input (10⁶ Btu/hr) - 66.8
Scrubbed Flue Gas:
Temperature (°F) - 130
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam:
Temperature (°F) - 366
Pressure (psia) - 165
Flow Rate (lbs/hr) - 75,800

Stack Exit Temperature (°F) - 180
Recirculation Exit Gas:
Temperature (°F) - 286
Flow Rate (lbs/hr) - 2,370,000
Reheat Air:
Ambient Temperature (°F) -
Heated Temperature (°F) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger:	4	31,300 sq ft ^a	\$ 20 sq ft	626,000
Exit Temp (°F) - 286				
Exchanger IP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b -			20.8	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^c -				
Primary Fan ^d				
Size (HP) - 2785	4		\$ - each	-
IP (in. H ₂ O) - 34				
Auxiliary Fan ^e				
Size (HP) - 6	4	182 (HP)	\$ 27,200 each	109,000
Incremental Stack Cost ^f	8		\$ 1,700 each	14,000
Soot Blowers				
Total Equipment Cost ^g				749,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				509,000
Indirect Costs (-5% of Total Equipment and Direct Labor & Material Costs)				366,000
TOTAL CAPITAL INVESTMENT				1,824,000

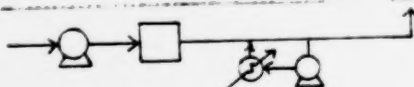
OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	75,800 (lbs/hr)	1.57 (\$ 10/lbs)	832,000
Electricity			
Primary Fan	- (kw)	- (\$/kwh)	-
Auxiliary Fan	543 (kw)	0.0314 (\$/kwh)	119,000
Maintenance and Replacement Cost			197,000
Depreciation			73,000
TOTAL ANNUAL OPERATING COST			1,221,000
ANNUAL REVENUE REQUIRED			1.39 x 10 ⁶

^a Area shown is 15% greater than area calculated.
^b Overall heat transfer coefficient for condensing portion of exchanger.
^c Overall heat transfer coefficient for desuperheat portion of exchanger.
^d Primary fan's base size corresponds to a forced draft FGD process without reheat.
^e Auxiliary fan required for indirect hot air and exit gas recirculation configurations.
^f Incremental stack cost experienced only with indirect hot air configuration.
^g Total cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-35. COST SUMMARY SHEET FOR EXIT GAS RECIRCULATION
REHEAT (165 psia, dry saturated steam; flue gas
approach temperature = 120°F)

CONFIGURATION



Required Heat Input (10⁶ Btu/hr) - 66.8
Scrubbed Flue Gas
Temperature (°F) - 130
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam
Temperature (°F) - 366
Pressure (psia) - 165
Flow Rate (lbs/hr) - 74,700

Stack Exit Temperature (°F) - 180
Recirculation Exit Gas
Temperature (°F) - 246
Flow Rate (lbs/hr) - 3,850,000
Reheat Air
Ambient Temperature (°F) -
Heated Temperature (°F) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	21,000 ft ²	\$ 20 ft ²	420,000
Exit Temp (°F) - 246				
Exchanger DP (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^a			28.5	
Superheat Heat Transfer Coefficient (Btu/hr-ft ² -°F) ^b			-	
Primary Fan ^c				
Size (HP) - 2755	4		\$ - each	-
DP (in. H ₂ O) - 34				
Auxiliary Fan ^d				
Size (HP) - 6	4	295 (HP)	\$ 35,000 each	140,000
DP (in. H ₂ O) - 6				
Incremental Stack Cost ^e				
Stack Cost ^f	8		\$ 1,700 each	14,000
Soot Blowers				
Total Equipment Cost ^g				574,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				371,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				425,000
TOTAL CAPITAL INVESTMENT				1,370,000

OPERATING COSTS

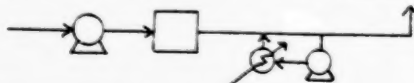
Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	74,700 (lbs/hr)	1.57 (\$ 10 ⁶ /hr)	820,000
Electricity			-
Primary Fan	- (kw)	- (\$/kw)	193,000
Auxiliary Fan	880 (kw)	0.0314 (\$/kw)	139,000
Maintenance and Replacement Cost			55,000
Depreciation			1,207,000
TOTAL ANNUAL OPERATING COST			1.34 x 10 ⁶
ANNUAL REVENUE REQUIRED			

^aArea shown is 25% greater than area calculated.
^bOverall heat transfer coefficient for condensing portion of exchanger.
^cOverall heat transfer coefficient for superheat portion of exchanger.
^dPrimary fan's base size corresponds to a forced draft FGD process without reheat.
^eAuxiliary fan required for indirect hot air and exit gas recirculation configurations.
^fIncremental stack cost experienced only with indirect hot air configuration.
^gTotal cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

Reproduced from
best available copy.

TABLE E-36. COST SUMMARY SHEET FOR EXIT GAS RECIRCULATION
REHEAT SENSITIVITY (Case A)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 66.8
Scrubbed Flue Gas:
Temperature ($^{\circ}$ F) - 130
Flow Rate (lbs/hr) - 5,140,000
Reheat Steam:
Temperature ($^{\circ}$ F) - 745
Pressure (psia) - 165
Flow Rate (lbs/hr) - 61,800

Stack Exit Temperature ($^{\circ}$ F) - 180
Recirculation Exit Gas:
Temperature ($^{\circ}$ F) - 310
Flow Rate (lbs/hr) - 1,920,000
Reheat Air:
Ambient Temperature ($^{\circ}$ F) -
Heated Temperature ($^{\circ}$ F) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	30,900 (sq ft)	\$ 20 each	616,000
Exit Temp ($^{\circ}$ F) - 310				
Exchanger IP (in H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu/hr-sq ft- $^{\circ}$ F) - 19.9				
Superheat Heat Transfer Coefficient (Btu/hr-sq ft- $^{\circ}$ F) - 17.7				
Primary Fan				
Size (HP) - 2755	4		\$ - each	-
IP (in H ₂ O) - 34				
Auxiliary Fan				
Size (HP) - 6	4	148 (HP)	\$24,500 each	98,000
Incremental Stack Cost ⁶				-
Stack Blowers	8		\$1,700 each	14,000
Total Equipment Cost ⁶				728,000
Direct Labor and Materials Cost (for exchanger and stack blower installation)				504,000
Indirect Costs (45% of Total Equipment and Direct Labor & Material Costs)				554,000
TOTAL CAPITAL INVESTMENT				1,786,000

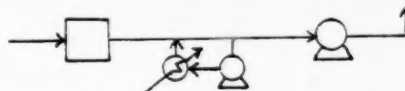
OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	61,800 (lbs/hr)	1.93 (\$ 10/lbs)	837,000
Electricity			
Primary Fan	- (kw)	- (\$ 1/kw)	-
Auxiliary Fan	442 (kw)	0.0314 (\$ 1/kw)	97,000
Maintenance and Replacement Cost			193,000
Depreciation			71,000
TOTAL ANNUAL OPERATING COST			1,198,000
ANNUAL REVENUE REQUIRED			1.37×10^6

Area shown is 15% greater than area calculated.
Overall heat transfer coefficient for condensing portion of exchanger.
Overall heat transfer coefficient for desuperheating portion of exchanger.
Primary fan's base size corresponds to a forced draft FGD process without reheat.
Auxiliary fan required for indirect hot air and exit gas recirculation configurations.
Incremental stack cost experienced only with indirect hot air configuration.
Total cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-37. COST SUMMARY SHEET FOR EXIT GAS RECIRCULATION
REHEAT SENSITIVITY (Case B)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 66.6
 Scrubbed Flue Gas
 Temperature ($^{\circ}$ F) - 126
 Flow Rate (lbs/hr) - 5,120,000
 Reheat Steam:
 Temperature ($^{\circ}$ F) - 366
 Pressure (psia) - 165
 Flow Rate (lbs/hr) - 49,500

Stack Exit Temperature ($^{\circ}$ F) - 176
 Recirculation Exit Gas
 Temperature ($^{\circ}$ F) - 286
 Flow Rate (lbs/hr) - 1,290,000
 Reheat Air
 Ambient Temperature ($^{\circ}$ F) -
 Heated Temperature ($^{\circ}$ F) -
 Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger:	4	19,700 ft^2 ^a	20 ft^2	394,000
Exit Temp ($^{\circ}$ F) - 286				
Exchanger P (in. H ₂ O) - 6				
Condensing Heat Transfer Coefficient (Btu hr- ft^2 - $^{\circ}$ F) ^b			20.3	
Superheat Heat Transfer Coefficient (Btu hr- ft^2 - $^{\circ}$ F) ^c			-	
Primary Fan				
Size (HP) - 2350	4		\$ <36,400> each	<146,000>
P (in. H ₂ O) - 34				
Auxiliary Fan ^d				
P (in. H ₂ O) - 6	4	104 (HP)	\$ 21,600 each	87,000
Incremental Stack Cost ^e				
Stack Blowers	8		\$ 1,700 each	14,000
Total Equipment Cost ^f				349,000
Direct Labor and Materials Cost (for exchanger and stack blower installation)				353,000
Indirect Costs (4% of Total Equipment and Direct Labor & Material Costs)				316,000
TOTAL CAPITAL INVESTMENT				1,018,000

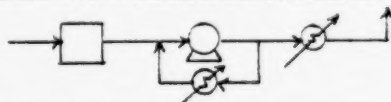
OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	49,500 (lbs/hr)	1.57 (\$ 10 ⁶ /lbs)	543,000
Electricity			
Primary Fan	<1200> (kw)	0.0314 (\$/kw)	<264,000>
Auxiliary Fan	310 (kw)	0.0314 (\$/kw)	68,000
Maintenance and Replacement Cost			128,000
Depreciation			41,000
TOTAL ANNUAL OPERATING COST			516,000
ANNUAL REVENUE REQUIRED			.61 x 10 ⁶

- ^a Area shown is 15% greater than area calculated.
^b Overall heat transfer coefficient for condensing portion of exchanger.
^c Overall heat transfer coefficient for desuperheat portion of exchanger.
^d Primary fan's base size corresponds to a forced draft FGD process without reheat.
^e Auxiliary fan required for indirect hot air and exit gas recirculation configurations.
^f Incremental stack cost experienced only with indirect hot air configuration.
^g Total cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

TABLE E-38. COST SUMMARY SHEET FOR EXIT GAS RECIRCULATION
REHEAT SENSITIVITY (Case C)

CONFIGURATION



Required Heat Input (10^6 Btu/hr) - 66.6
Scrubbed Flue Gas:
Temperature ($^{\circ}\text{F}$) - 125
Flow Rate (lbs/hr) - 5,120,000
Reheat Steam
Temperature ($^{\circ}\text{F}$) - 366
Pressure (psia) - 165
Flow Rate (lbs/hr) - 13,700; 33,900

Stack Exit Temperature ($^{\circ}\text{F}$) - 175
Recirculation Exit Gas
Temperature ($^{\circ}\text{F}$) - 286
Flow Rate (lbs/hr) - 337,000
Reheat Air
Ambient Temperature ($^{\circ}\text{F}$) -
Heated Temperature ($^{\circ}\text{F}$) -
Flow Rate (lbs/hr) -

EQUIPMENT SPECIFICATIONS AND CAPITAL INVESTMENT

Item	No. Req'd.	Total Capacity	Total - Incremental Cost Unit	Total Cost (\$)
Reheat Exchanger	4	3300	\$ 20	180,000
Exit Temp ($^{\circ}\text{F}$) - 286; 176		5700		
Exchanger LP (in. H ₂ O) - 30; 3				
Condensing Heat Transfer Coefficient ($\text{Btu/hr-ft}^2\text{-}^{\circ}\text{F}$) ^b -			33.4; 31.7	
Superheat Heat Transfer Coefficient ($\text{Btu/hr-ft}^2\text{-}^{\circ}\text{F}$) ^c -			-	
Primary Fan				
Size (HP) 2620	4		\$ <21,000> each	<84,000>
P (in. H ₂ O) - 37				
Auxiliary Fan ^d				
P (in. H ₂ O) - -	-	(HP)	\$ - each	-
Incremental Stack Cost ^e				-
Soot Blowers	8		\$ 1,700 each	14,000
Total Equipment Cost ^f				110,000
Direct Labor and Materials Cost (for exchanger and soot blower installation)				210,000
Indirect Costs (+5% of Total Equipment and Direct Labor & Material Costs)				144,000
TOTAL CAPITAL INVESTMENT				464,000

OPERATING COSTS

Item	Quantity Required	Cost Unit	Total Annual Cost (\$)
Steam Hot Water	47,600 (lbs/hr)	1.57 (\$ 10 lbs)	522,000
Electricity			
Primary Fan	<400> (kw)	0.0314 (\$/kwh)	<88,000>
Auxiliary Fan	- (kw)	- (\$/kwh)	-
Maintenance and Replacement Cost			58,000
Depreciation			19,000
TOTAL ANNUAL OPERATING COST			511,000
ANNUAL REVENUE REQUIRED			0.56×10^6

^a Area shown is 15% greater than area calculated.
^b Overall heat transfer coefficient for condensing portion of exchanger.
^c Overall heat transfer coefficient for desuperheat portion of exchanger.
^d Primary fan's base size corresponds to a forced draft FGD process without reheat.
^e Auxiliary fan required for indirect hot air and exit gas recirculation configuration.
^f Incremental stack cost experienced only with indirect hot air configuration.
^g Total cost of equipment that is needed as a result of reheat. The fan and incremental stack costs included in this total are installed costs.

APPENDIX F

FACTORS FOR CONVERSION OF ENGLISH UNITS TO THE
INTERNATIONAL SYSTEM OF UNITS (SI)

English Units	Multiplication Factor For Conversion	SI Units
Btu	1.06×10^3	joule (J)
Btu/hr	2.92×10^{-1}	watt (W)
Btu/hr-ft ² -°F	5.67	watt/meter ² -°C (W/m ² -°C)
Btu/kWh	1.06	joule/watt-hour (J/Wh)
Btu/lb _m	2.32×10^3	joule/kilogram (J/kg)
Btu/lb _m -°F	4.18×10^3	joule/kilogram-°C (J/kg-°C)
ft ₂	3.05×10^{-1}	meter (m)
ft/sec	3.05×10^{-1}	meter/second (m/s)
ft ³ /min	4.72×10^{-4}	meter ³ /second (m ³ /s)
gal/hr	1.05×10^{-6}	meter ³ /second (m ³ /s)
gr/scf (grain/std. cubic foot)	2.29×10^{-3}	kilogram/meter ³ (kg/m ³)
hp (horsepower)	7.46×10^{-2}	watts (W)
inch	2.54×10^{-2}	meters (m)
in. H ₂ O @ 60°F	2.49×10^2	pascal (Pa)
kWh	3.60×10^6	joule (J)
mile	1.61×10^3	meter (m)
lb _m	4.54×10^{-1}	kilogram (kg)
lb _m /hr	1.26×10^{-4}	kilogram/second (kg/s)
lb _f /in. ²	6.89×10^3	pascal (Pa)
lb _m /sec	4.54×10^{-1}	kilogram/second (kg/s)

Temperature Conversions:

$$T(^{\circ}\text{C}) = 0.56[T(^{\circ}\text{F}) - 32]$$

$$T(^{\circ}\text{K}) = 0.56[T(^{\circ}\text{R})]$$